EXHIBIT A

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of FirstEnergy Pennsylvania Electric Company for Approval of Its Default Service Program for the Period June 1, 2027 to May 31, 2031	: : : :	Docket No. P-2026-3060298

DIRECT TESTIMONY AND EXHIBITS OF
THOMAS S. MICHELMAN

ON BEHALF OF

THE COALITION FOR COMMUNITY SOLAR ACCESS AND
SOLAR ENERGY INDUSTRIES ASSOCIATION
"Joint Solar Advocates"

Statement No. 1

Topics Addressed:
FirstEnergy Pennsylvania's Maximum Registered Peak Load Proposal

Date Served: April 29, 2026

Date Submitted for the Record: ____________

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Thomas S. Michelman. I am the Vice President & Senior Director, Distributed Energy Resources Practice Lead for Sustainable Energy Advantage, LLC ("SEA"). My business address is 161 Worcester Road, Suite 503, Framingham, MA 01701.

Q. Please describe your experience and qualifications.

A. I have been working in the energy industry since 1993, when I joined Xenergy, Inc. ("Xenergy") as an energy efficiency analyst. Beginning in 1996, much of my work efforts at Xenergy were focused on analyzing electric industry restructuring and competitive retail choice. In 2003, I co-founded Boreal Renewable Energy Development ("Boreal") which was focused on wind and solar development at commercial, industrial, and institutional sites. I joined SEA, a clean energy consulting firm focused on the tracking and analysis of northeast clean energy markets (*i.e.,* ISO-NE, NYISO, and PJM). At SEA, I am now Vice President & Senior Director.

In regard to my education, I have a B.A. in Mathematical Methods in Social Sciences/Political Sciences from Northwestern University and an M.S. in Resource Economics from the University of Rhode Island My resume is attached as Exhibit TM-1.

Q. Please describe more specifically your experience with issues applicable to net metering and other distributed energy resources.

A. I have significant experience with issues related to net metering and other distributed energy resources ("DERs"). Since 1993, my professional area of focus has been exclusively in the DER sector. As mentioned above, beginning in 1996, I focused much of my work at Xenergy on analysis of electric industry restructuring and competitive retail choice issues. At Xenergy, I led and/or was a major contributor to analyzing the frequently evolving and growing retail electric choice markets, including markets in the Commonwealth of Pennsylvania[1].

During my time working at Boreal, DER issues and net metering opportunities and constraints were almost always an important consideration about whether a renewable project was viable, and I therefore gained substantial in-practice expertise in those matters. For example, I provided expert testimony on the proposed NSTAR distributed generation ("DG") standby rates (Massachusetts Department of Telecommunications and Energy ("DTE") Docket No. 03-121) and their effect on the economics of DG wind turbine installations for the Conservation Law Foundation and Solar Energy Business Association of New England. The Massachusetts DTE approved a settlement to which NSTAR was a signatory that exempted renewable installations from standby rates. In addition, I was a lead participant in crafting a consensus for Massachusetts' innovative "virtual" net metering legislation (supporting wind and solar photovoltaic ("PV") projects) which was incorporated into the Green Communities Act signed into law in July 2008. Subsequently, beginning in 2008, I was involved in many hearings and technical sessions creating regulations and utility net metering tariffs. To support clients, I developed substantial expertise on net metering and the important underlying utility rate drivers.

I joined SEA in 2013 to lead SEA's analysis of the growing DER solar markets. I conducted dozen, if not hundreds, of different types of DER-focused analyses. My clients have included clean energy developers and their financers, industry trade groups, government agencies, large consumers of electricity, and at least one regulated electric

[1] At Xenergy, I was recognized by colleagues for my detailed knowledge of Pennsylvania's electric restructuring market and was considered to be the "go-to" resource on all matters related to electric restructuring in Pennsylvania.

utility. Specifically related to net metering, I led the practice of analyzing and forecasting DER compensation rates, which for most DER markets (similar to DER net metering compensation in Pennsylvania) is based on derivatives of retail rates. My SEA colleagues and I pride ourselves on conducting detailed, "bottom-up" analyses and forecasts drawing the connections (and disconnections) between the wholesale markets, regulatory filings, external market drivers, and the applicable DER compensation rates. I have led the analysis and forecasts of DER compensation rates for the Connecticut, Delaware, Washington D.C., Illinois, Massachusetts, Maryland, New Jersey, New Mexico, New Hampshire, Rhode Island, Vermont, and Pennsylvania markets. The Pennsylvania DER markets included PECO, PPL, and the First Energy territories of Met-Ed, Penelec, and West Penn Power.

For my work in regulatory and policy issues, some key highlights of my work include managing the analysis for the Massachusetts Department of Energy Resources' ("MA DOER") policy alternatives for a successor program to its Solar Energy Renewable Energy Certificates II program. I led the analysis as a key participant and co-contributor for the Massachusetts Net Metering and Solar Task Force Report jointly for the MA DOER and the Massachusetts Department of Public Utilities. More recently, for the Maine Public Utilities Commission, I served as expert witness in Docket No. 2024-00149 in the Maine Commission's Investigation into Allocation of Benefits of Distributed Generation under Net Energy Billing, which was a benefit-cost analysis of Maine's net metering program.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Coalition for Community Solar Access and the Solar Energy Industries Association, jointly called the "Joint Solar Advocates" or "JSA.".

Q. Have you previously submitted testimony before the Pennsylvania Public Utilities Commission?

A. No.

Q. What states have you submitted testimony to the authority having jurisdiction over public utilities?

A. Maine and Massachusetts.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide recommendations for improvements to FirstEnergy Pennsylvania Electric Company's ("FE") proposed Default Service Plan VII ("DSP VII" or "DSP") regarding its treatment of net-metered customer-generators.

My testimony will:

- Explain the important benefits that net-metered customer-generators provide to FE and its ratepayers that FE failed to recognize in its Petition of FirstEnergy Pennsylvania Electric Company for Approval of Its Default Service Program for the Period June 1, 2027 to May 31, 2031 ("Petition"). FE failed to recognize the energy, capacity, and transmission costs that net-metered excess generation allows FE, its suppliers, and ultimately its customers to avoid. As a result, FE inaccurately overestimated the impact of net-metering customer-generators on the Commercial Price-to-Compare ("PTC") Rider rates.
- Discuss and analyze the consequences of FE's proposal to shift net-metered customer-generators from the Commercial default service class to the Industrial default service class that could be avoided with improvements to the FE's proposed DSP VII.

- Recommend improvements to the DSP VII so that the benefits to FE customers from net-metered excess generation can be fully recognized.

I also discuss FE's proposed DSP VII and testimony in detail and explain and correct misconceptions using industry specific concepts and terminology, which I have included in Appendix A attached to my testimony.

My specific recommendations are:

1. The Commission should require FE to modify how it calculates customer peak loads used to determine generation capacity and transmission cost allocation by: (1) allowing customers to register "negative loads" as a result of the excess generation they produce; and (2) apply the cost savings of those negative loads to reduce the allocation of the relevant costs to the default service class in which the customer-generator is assigned.
2. The Commission should approve my proposal for establishing legacy rights under the Commercial PTC Rider for all net-metered customer-generators that are operational or provide a completed copy of their Certificate of Completion[2] to FE on or before June 1, 2027.
3. The Commission should approve my proposal for establishing legacy rights under the Commercial PTC Rider, at a reduced rate, for all net-metered customer-generators that meet certain project development maturity milestones on or before June 1, 2027.

II. DEFINING THE PROBLEM REGARDING NET-METERED CUSTOMER-GENERATORS THAT FE SEEKS TO ADDRESS

Q. Please outline the basic "problem" that FE's proposal seeks to address.

[2] A Certificate of Completion, as defined in 52 Pa. Code § 75.22, is a certificate in a form approved by the Commission containing information about the interconnection equipment to be used, its installation, and local inspections.

A. FE states in its Petition there has been an increase in 1 to 3-megawatt ("MW") solar projects applying for interconnection with the intent of becoming net-metered customer-generators.[3] FE claims that the growth of net-metered customer-generators served by the Commercial PTC Rider will cause upward pressure on Commercial PTC Rider rates. FE asserts that these rate increases are primarily due to the following:

- Net metering cash-out payments to customer-generators will increase as more projects come online, with those net-metering expenses recovered from the Commercial default service class; and,
- Excess generation from net-metered projects decreases the load provided by default service suppliers, thereby increasing the risk premiums included in bids to supply the Commercial default service class.[4]

FE proposes to shift net-metered customer-generators from the Commercial default service class to the Industrial default service class due to its claim of future rate increases. FE proposes moving both new and legacy net-metered projects to the Industrial Hourly Pricing Rider ("HP Rider") by changing the eligibility criteria for assigning a customer's default service class from peak load consumption alone to a consideration of both peak load and the Maximum Registered Peak Load ("MRPL"). As a result of that proposed change, net-metered excess generation from large customer-generators would be compensated based on the HP Rider rate and the costs to pay for the net-metered excess generation would be recovered in the HP Rider. The HP Rider rates are calculated using real-time pricing based on the hourly generation needs of customers. FE proposes that the reclassification of certain net-metered projects based on the MRPL would occur in 2027

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[3] FE PA Statement No. 1, 17:8-10.
[4] *Id*. at 17:15-18:2.

for new net-metered projects and in 2029 for net-metered projects that are operational on or before June 1, 2027.[5]

Q. Does FE attempt to quantify the impact of net-metered customer-generators due to the growth of net metering expenses included in Commercial PTC Rider rates?

A. Yes, the impact is quantified in FE PA Exhibit DMY-7 ("Exhibit DMY-7"), "Analysis of Net Metering Cash Out Expense Impact on Price to Compare Default Service Rate Rider." The exhibit purports to show that for the time period of June 1, 2024 to May 31, 2025, the true-up expense recovered from Commercial PTC Rider customers totaled just over $4.4 million. The exhibit also purports to show that "if as little as 10% of the proposed projects in the current applications come online by 2029, the true-up expense in 2029 will be approximately $81 million."[6]

Q. Do you believe that FE's calculations in Exhibit DMY-7 are accurate?

A. No. FE's analysis is deficient because it fails to account for the cost reduction benefits accrued to Commercial default service customers on the PTC Rider that result from the growth in net-metered excess generation.

Q. What quantifiable benefits did FE fail to include in its analysis provided in Exhibit DMY-7?

A. FE failed to include the benefits of net-metered excess generation in reducing default service suppliers' cost to serve the Commercial default service class through the competitive bidding process and through credits incorporated into the calculation of the "E-PTC" component in the PTC Rider rate setting reconciliation process. These major benefits result from default service suppliers procuring less energy, and, if the JSA's

[5] FE PA Statement No. 1, 19:19-22.
[6] *Id.* at 18:18-20.

recommendations discussed later in my testimony are incorporated, procuring less capacity and transmission services as well. While the benefits are real, the manner in which they are reflected in the PTC Rider varies by each reduced cost component.

Q. Can you provide additional information to further explain the benefits of net-metered excess generation?

A. The below Table 1 provides a summary of the cost components from which a default service provider's (and more generally a load serving entity's) cost obligations are determined by FE Rate District.

Table 1: Summary of Major FE Cost Components for Generation Supply

FE Rate District	Energy Component	Capacity Component	Transmission Component
Met-Ed[7]	Met-Ed class load	Met-Ed Zone	Met-Ed utility Zone within MAIT[8]
Penelec[9]	Penelec class load	Penelec Zone	Penelec utility Zone within MAIT
Penn Power[10]	Penn Power class load	ATSI	Penn Power utility Zone within ATSI[11]
West Penn Power[12]	West Penn Power class load	APS	West Penn Power utility Zone within APS[13]

As will be discussed in detail later in my testimony, the sharing of a capacity or transmission component across a PJM zone allows some benefits provided by Pennsylvania net metering customer-generators to accrue to ratepayers outside of the

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[7] *See* Met-Ed's ME Supplier Energy Obligation manual and ME Supplier Capacity Manual.
[8] Mid-Atlantic Interstate Transmission, LLC (MAIT) includes transmission facilities that serve Met-Ed, Penelec, and the MAIT Transmission Zone.
[9] *See* PN Supplier Energy Obligation manual and PN Supplier Capacity Manual.
[10] *See* Penn Power's Supplier Energy Obligation and Supplier Capacity Manual.
[11] American Transmission Systems, Inc. (ATSI) and AMP Transmission, LLC both serve the ATSI Transmission Zone. The ATSI Transmission Zone includes Ohio Edison, Cleveland Electric Illuminating Company, Cleveland Public Power, Toledo Edison (all in Ohio) and Penn Power.
[12] *See* West Penn Power's Supplier Energy Obligation manual and Supplier Capacity Manual.
[13] The Allegheny Power System (APS) Zone includes Monongahela Power Company (West Virginia), The Potomac Edison Company (Maryland and Virginia), and West Penn Power (Pennsylvania).

Commonwealth of Pennsylvania, an issue that can be mitigated by allowing customer-assigned peak loads to be negative.

III. BENEFITS OF NET-METERED EXCESS GENERATION IN REDUCING THE DEFAULT SERVICE SUPPLIER'S COST TO SERVE

A. Net-metered Excess Generation Reduces Energy Costs

Q. Does net-metered excess generation lower the net energy component of the Commercial PTC Rider rate and provide benefits to Commercial PTC Rider customers?

A. It does so through the following Steps:

Step 1. Net-metered generation lowers the PJM Settled Load for the default service customer class to which it is classified.

Step 2. This lowers the default service supplier's wholesale load obligation for the customer class.

Step 3. This then lowers FE's payments to the default service supplier for the customer class (*i.e.*, "Payments to Winning Bidders").

Step 4. This lower payment shows up in the computation of the Over/Under Collections, as shown in Line 3 of Figure 1 below.[14] All other things being equal, the lower payments to default service suppliers as winning bidders result in an over collection of revenue from Commercial PTC Rider customers (the "Ending Cumulative (Over)/Under Collection" shown in Line 17 of Figure 1 below).[15]

Figure 1 – Met-Ed Commercial PTC Rider Rate Example - Statement of Revenues and Expenses for the Six Month Period Ended March 31, 2024

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[14] *See*, for example, Exhibit TM-2 (FE PA Response to CGC Interrogatory Set 1, No. 22, Attachment B) at 14. At the most granular level, *see* Line No. 3 "Payment to Winning Bidders.

[15] *Id*. *See*, Line No. 17 "Ending Cumulative (Over)/Under Collection."

FirstEnergy Pennsylvania Electric Company - Met-Ed Rate District
Price to Compare Default Service ("PTC") Rider Rates - Commercial Class
For the Default Service Period June 1, 2024 through November 30, 2024
Statement of Revenues and Expenses for the Six Month Period Ended March 31, 2024

Line No.	Description	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24
1	Revenues applied to Current, net of GRT	$ 6,322,360	$ 6,046,091	$ 14,864,321	$ (480,302)	$ 7,320,444	$ 6,540,693
	Expenses						
2	Administrative Costs	$ -	$ 6,823	$ 8,407	$ 4,586	$ -	$ 528
3	+ Payments to Winning Bidders	6,043,870	6,427,427	7,903,242	8,615,632	4,941,616	6,250,191
4	+ Net Metering Costs (Credits)	51,466	53,233	8,641,717	(8,800,484)	76,894	71,296
5	+ Ancillary Services	-	-	-	-	-	-
6	Total Expenses	$ 6,095,335	$ 6,487,483	$ 16,553,366	$ (180,267)	$ 5,018,510	$ 6,322,015
7	Current (Over)/Under Collection (Line 6 - Line 1)	$ (227,025)	$ 441,392	$ 1,689,045	$ 300,035	$ (2,301,934)	$ (218,678)
8	Annual Interest Rate	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
9	Monthly Interest Rate (Line 8 / 12)	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
10	Months to the Midpoint of the Collection Period	11	10	9	8	7	6
11	Regulatory Interest (Lines 7 x 9 x 10)	$ (12,486)	$ 22,070	$ 76,007	$ 12,001	$ (80,568)	$ (6,560)
12	Total Current (Over)/Under Collection and Interest (Lines 7+11)	$ (239,511)	$ 463,462	$ 1,765,052	$ 312,036	$ (2,382,502)	$ (225,238)
13	Cumulative Current (Over)/Under Collection and Interest	$ (239,511)	$ 223,951	$ 1,989,003	$ 2,301,039	$ (81,463)	$ (306,701)

Cumulative (Over)/Under Collection for the Six Month Period Ended March 31, 2024

Line No.	Description	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24
14	Beginning Cumulative (Over)/Under Collection	$ 622,802	$ 1,068,542	$ 1,494,805	$ 1,956,247	$ 1,972,258	$ 1,728,222
15	+ Revenue Applied to E-factor, net of GRT	445,740	426,263	461,442	16,011	(244,036)	(218,042)
16	+ Total Current (Over)/Under Collection and Interest (Line 13)	-	-	-			(306,701)
17	Ending Cumulative (Over)/Under Collection	$ 1,068,542	$ 1,494,805	$ 1,956,247	$ 1,972,258	$ 1,728,222	$ 1,203,479

Step 5. "Ending Cumulative (Over)/Under Collection" is then used as the "PTC (Over)/Under Collection",[16] as shown in Line 1 of Figure 2 below, to compute the "E-PTC" (*i.e.*, the reconciliation charge).

[16] Exhibit TM-2 (FE PA Response to CGC Interrogatory Set 1, No. 22, Attachment B) at 13. *See*, Line No. 1.

Figure 2 – Met-Ed Commercial PTC Rider Rate Example – Computation of E-PTC (Over)/Under Collection Rate

FirstEnergy Pennsylvania Electric Company - Met-Ed Rate District
Price to Compare Default Service ("PTC") Rider Rates - Commercial Class
For the Default Service Period June 1, 2024 through November 30, 2024
Computation of E - PTC (Over)/Under Collection Rate

Line No.	Description		Amounts
1	PTC (Over)/Under Collection (Page 3, Line 17)	$	1,203,479
2	+ Capacity Proxy Price True-Up		(42,534)
3	+ Projected E-factor revenue for the remainder of the Default Service Period beginning December 1, 2023		(464,748)
4	+ Projected (Over)/Under Collection for the remainder of the Default Service Period beginning December 1, 2023		372,871
5	PTC (Over)/Under Collection, as adjusted	$	1,069,068
6	DS $_{Sales}$ - Six months sales forecast (kWh)		435,168,923
7	E - PTC (Over)/Under Collection (per kWh)	$	0.00246
8	x Gross up for Gross Receipts Tax (GRT = 5.90%)		1.062699
9	**E - PTC (Over)/Under Collection including GRT (per kWh)**	**$**	**0.00261**

Step 6. Finally, the E-PTC value is included as the "E - PTC (Over)/Under Collection"[17] component in the computation of the PTC Default Rate, as shown in Line 14 of Figure 3 below.

[17] Exhibit TM-2 (FE PA Response to CGC Interrogatory Set 1, No. 22, Attachment B) at 12. *See*, Line No. 14.

Figure 3 – Met-Ed Commercial PTC Rider Rate Example for the Default Service Period June 1, 2024 through November 30, 2024

FirstEnergy Pennsylvania Electric Company - Met-Ed Rate District
Price to Compare Default Service ("PTC") Rider Rates - Commercial Class
For the Default Service Period June 1, 2024 through November 30, 2024

Line No.	Description	Tranches Procured	Winning Price (per MWh)	Weighted Auction Price (per MWh)	PTC Component (per kWh)
	Auction Results				
1	January 2023 Auction (June 23 through May 25)	1	$ 89.21	$ 9.91	
2	April 2023 Auction (June 23 through May 25)	2	107.74	23.94	
3	November 2023 Auction (June 24 through May 25)	2	88.03	19.56	
4	November 2023 Auction (June 24 through May 26)	1	90.41	10.05	
5	April 2024 Auction (June 24 through May 25)	2	85.22	18.94	
6	April 2024 Auction (June 24 through May 26)	1	90.12	10.01	
7	PTC $_{\text{Current Cost Component}}$	9		$ 92.41	$ 0.09241
8	x PTC Loss $_{\text{Current}}$				1.0515
9	Loss Adjusted PTC $_{\text{Current Cost Component}}$				$ 0.09717
10	+ PTC $_{\text{Adm}}$				0.00006
11	PTC $_{\text{Current}}$				$ 0.09723
12	x Gross up for Gross Receipts Tax (GRT = 5.90%)				1.062699
13	PTC $_{\text{Current}}$ including Gross Receipts Tax				$ 0.10333
14	+ E - PTC (Over)/Under Collection (Page 2, Line 9)				0.00261
15	**PTC $_{\text{Default}}$ Rate**				**$ 0.10594**

(A) Computations pursuant to the terms of the Company's "Price to Compare Default Service Rate Rider"
(B) Adders subject to semi-annual updates

Q. Please provide further information about Step Nos. 1, 2, 3 that you listed above.

A. These linkages are clear and straightforward, as documented in the Supplier Master Agreement published on FirstEnergy's Pennsylvania Default Service Program website and are consistent with FE's testimony and responses to interrogatories.[18]

[18] *See*, for example, Exhibit TM-3 (FE PA Response to CGC Interrogatory Set 1, No. 020).

Q. Please provide additional explanation about Step No. 4. Specifically, if "Payments to Winning Bidders" decrease, why would the "Revenues applied to Current, net of GRT" not also decrease?

A. The values in "Revenues applied to Current, net of GRT"[19] (Line 1 of Figure 1 above) are based on the aggregated metered load of Commercial PTC Rider customers while the "Payment to Winning Bidders" (Line 3 of Figure 1) is based on metered load net of production from net-metered customer-generators.

Q. Would the aggregated metered load also decrease with additional net-metered excess generation?

A. No. The aggregated metered load does not decrease with additional net-metered generation because the net-metered production is accounted for implicitly as "Net Metering Costs (Credits)" (Line 4 of Figure 1). As an example, assume that there are two commercial customers on the PTC Rider. The first is a typical customer consuming 10,000 kWh in a month; the second is a net-metered customer-generator that produces 7,000 kWh per month and consumes 500 kWh per month in station load at its net-metered generation facility.[20] The net load at the wholesale level by which the "Payment to Winning Bidders" is calculated equals 3,500 kWh (10,000 + 500 – 7,000) because the 6,500 kWh that is exported from the net-metered customer-generator serves part of the 10,000 kWh in consumption from the non-generating customer. In contrast, the two PTC Rider customers pay the PTC rate for 10,500 kWh (10,000 + 500) because that is what is registered by their retail meters, which do not distinguish between whether the energy supplied came from a net-metered customer-generator or the bulk power grid.

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[19] Exhibit TM-2 (FE PA Response to CGC Interrogatory Set 1, No. 22, Attachment B) at 14. *See,* Line No. 1.

[20] For simplicity's sake in this example, I did not assume any line losses in this example.

Q. Please refer to Exhibit DMY-7 (FE's customer-generator cost impact analysis), and please explain what is included and what is excluded in the calculation of net-metered customer-generators' impact on Commercial PTC Rider rates?

A. FE's Exhibit DMY-7 includes the costs of providing credits to net-metered customer-generators but excludes the benefits of the reduced energy supply costs that will result from their output. "Net Metering Costs (Credits)" are included in the calculation of the impact of net-metered customer-generators on PTC Rider rates, but the benefits of decreases in costs found in "Payment to Winning Bidders"[21] are not included in the calculation of the PTC Rate or the Estimated Net Metering Expense line items for the years 2026 through 2029. As Exhibit DMY-7 is supposed to be an "Analysis of Net Metering Cash Out Expense Impact on Price to Compare Default Service Rate Rider," FE should recalculate it to properly account for the impact of energy benefits derived from net-metered excess generation on Commercial PTC Rider rates, along with the reduction in capacity and transmission costs. FE's failure to do so results in a substantial overstating of the cost of net-metered customer-generators.

Q. Does this mean that the ratepayers that are bearing the costs of paying for net-metered energy generation (customers in the customer-generator's default service class) are also directly yielding the energy benefit from a utility accounting perspective?

A. Yes, that is correct. Of the three value streams I will discuss later in my testimony (energy, capacity, and transmission), the energy benefit is the only one that is currently being

[21] Exhibit TM-2 (FE PA Response to CGC Interrogatory Set 1, No. 22, Attachment B) at 14. See, Line No. 3.

distributed solely to the customers that are bearing the costs associated with compensating customer-generators.

B. Net-metered Excess Generation Reduces FE's Capacity Obligation

Q. What drives the capacity costs in FE's service territory?

A. At a high level, capacity costs are determined by the PJM capacity auction. The capacity auction incorporates forecasts of future demand and how much capacity will be required to meet that demand as part of a demand curve. Capacity costs, set by auction clearing prices, are then allocated based on customer demand during times of PJM system peak load, or the five coincident peak ("5CP") hours.

Q. What are the PJM 5CP hours and how are they determined?

A. The PJM 5CP hours are the five highest weekday one-hour peak load periods on the PJM system between June 1 and September 30 of every year. The 5CP hours are typically spread across multiple days during that period, as PJM excludes consecutive hours so that a single heat event over the course of one day does not dominate all five hours.

Q. Historically, when were the most common occurrences for the 5CP hours?

A. Between 2021 and 2025, all the PJM 5CP hours fell within the hours of 2:00 PM and 6:00 PM eastern daylight time ("EDT"), with the most common peak hour occurring between 5:00 PM and 6:00 PM EDT in July.

Table 2: Historical PJM 5CP Hours, 2021-2025[22]

Year	Peak 1	Peak 2	Peak 3	Peak 4	Peak 5
2021	Tues Jun 29 4-5 PM	Tues Jul 6 4-5 PM	Thurs Aug 12 4-5 PM	Tues Aug 24 5-6 PM	Thurs Aug 26 3-4 PM
2022	Weds Jul 20 5-6 PM	Thurs Jul 21 4-5 PM	Fri Jul 22 5-6 PM	Weds Aug 3 5-6 PM	Mon Aug 8 3-4 PM
2023	Weds Jul 5 5-6 PM	Thurs Jul 27 5-6 PM	Fri Jul 28 5-6 PM	Tues Sept 5 4-5 PM	Weds Sept 6 4-5 PM
2024	Fri Jun 21 5-6 PM	Mon Jul 15 5-6 PM	Tues Jul 16 5-6 PM	Aug 1 5-6 PM	Aug 28 5-6 PM
2025	Mon Jun 23 5-6 PM	Tues Jun 24 5-6 PM	Weds Jun 25 2-3 PM	Mon Jul 28 5-6 PM	Tues Jul 29 5-6 PM

Q. How does FirstEnergy assign capacity costs to its customers?

A. The process of taking costs from the PJM capacity auction and ultimately assigning those costs to individual customers involves the following steps:

Step 1. PJM Sets a Capacity Obligation and Solicits Capacity Bids. To determine how much generation capacity is needed to serve peak load, PJM forecasts system peak demand. From there, PJM targets an installed reserve margin ("IRM")—currently set around 20%—that is sufficient to meet the 1-in-10 loss of load reliability standard. This capacity obligation is procured through PJM's annual capacity auction, called the Base Residual Auction ("BRA"), which results in a \$/MW-day clearing price. In the latest BRA, which was conducted in December 2025 for the 2027/28 delivery year, prices across all zones cleared at the \$333.44/MW-day price cap. The auction procured 6,516.6 MW less than the

[22] https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/summer-2025-peaks-and-5cps.pdf , https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/summer-2024-peaks-and-5cps.pdf , https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/summer-2023-peaks-and-5cps.pdf , https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/summer-2022-peaks-and-5cps.pdf , https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/summer-2021-peaks-and-5cps.pdf

regional transmission organization ("RTO") reliability requirement, resulting in a 14.4% IRM, 5.6% below the target 20% reliability requirement.[23]

Step 2. FirstEnergy's Share of PJM Capacity Costs is Based on Customer Contribution to Peak Demand. PJM allocates system-wide capacity costs from the BRA to load serving entities ("LSEs") based on the percentage that overall customer demand represents relative to overall system demand during the 5CP hours.[24] Penelec, Met-Ed, West Penn Power, and Penn Power (*i.e.*, FE's Pennsylvania electric distribution companies), with their default service suppliers, each function as an LSE within PJM. For an example of how overall PJM costs are allocated to LSEs, in Summer 2025, the Met-Ed region had a weather normalized peak load of 2,940 MW relative to a PJM system-wide weather normalized peak load of 153,870 MW, representing 1.91% of the PJM peak. Met-Ed customers are thus collectively responsible for 1.91% of BRA costs.[25]

Step 3. Individual Customers are Allocated Capacity Costs Based on Their Actual or Imputed Contribution to Class Peak Load. Customer meters are used to measure each individual customer's demand during peak load hours, if they have a 15-minute interval meter, or peak load is imputed for other customers via rate class or customer class load profiles. Customers are then assigned an individual peak load contribution ("PLC") to determine their allocation of FE's overall capacity costs. The new PLCs for each customer are then effective from June 1 to the

[23] https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-bra-report.pdf
[24] https://agreements.pjm.com/oatt/4946
[25] https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/summer-2025-peaks-and-5cps.pdf

following May 31. For example, summer peaks in 2025 determine the PLCs assigned to each customer that are used from June 1, 2026 through May 31, 2027.

Step 4. FE then Allocates its Share of PJM Costs to Default Service Customer Classes by Aggregate PLC. For each default service class, FE calculates the contribution of each of its customer classes to overall peak load by calculating a class aggregate PLC. This metric is used to allocate FE's share of PJM capacity costs to each customer class. As an example, if Penelec's Commercial default service customer class represented 18% of Penelec's total peak load based on the 5CP hours, then the Penelec Commercial default service class would be allocated 18% of Penelec's share of overall capacity costs.[26]

Step 5. FE then Allocates the Customer Class Capacity Costs to Each Default Service Supplier. Each default service customer class is served by a different array of default service suppliers acting as load serving entities. Continuing with the example above if a default service supplier was serving 50% of Penelec's Commercial default service customer class, then that default service supplier would be liable for 9% (50% of 18%) of Penelec's capacity costs.

Q. How does net-metered excess generation from the Commercial default service customers lower the generation capacity obligation cost component of the PTC Rider rate?

[26] Note, these default service aggregate PLC metrics can and do change daily as FE customers move to and from default service. For this testimony it is easier to consider a simplified case where the aggregate PLC metric is stable for each PJM reliability year.

A. Net-metered excess generation produced during PJM's 5CP hours lowers the overall peak load and thus overall capacity cost obligations of the PJM capacity zone in which the customer-generator is located.

Q. How does the generation profile of a net-metered customer-generator align with the historical PJM 5CP hours shown in Table 3?

A. As discussed previously, the PJM 5CP hours occur between June 1 and September 30 each year. Over the past five years, the PJM 5CP hours have clustered between 2:00 PM and 6:00 PM EDT, with the most frequent occurring 5:00 PM to 6:00 PM EDT in July. Using capacity factor estimates from the System Advisory Model ("SAM") published by the National Laboratory of the Rockies, I produced an average capacity factor for a representative single-axis tracker ("SAT") project across the historical PJM 5CP hours combined with historical weather data.[27]

Table 3: Average Capacity Factor of SAT Solar PV Facility During Historical PJM 5CPs

	Avg 5CP	Peak 1	Peak 2	Peak 3	Peak 4	Peak 5
2021	58%	67%	66%	58%	37%	64%
2022	56%	64%	47%	57%	47%	64%
2023	49%	38%	64%	17%	64%	60%
2024	34%	9%	54%	46%	37%	26%

As shown in Table 3, solar production generally aligns with system peaks, producing an average capacity factor during 5CP hours of between 34% and 58% historically. Since this analysis uses historical weather years, the impact of variable weather (*e.g.*, cloudy days) is reflected in the results.

[27] Results end in 2024 given that weather data for 2025 was not available.

Q. Do net-metered customer-generators that produce during the 5CP hours receive a negative PLC?

A. No. Under FE's current practice, they do not. The minimum load that FE will assign a customer during an hour is zero MW, thus the lowest PLC a net-metered customer-generator can be assigned is a zero value PLC.

Q. Are negative PLCs prohibited by FERC or PJM?

A. No. In fact, FERC has explicitly approved the use of negative PLCs for another utility in the PJM. Commonwealth Edison ("ComEd") in Illinois has implemented a wholesale tariff allowing for a negative customer-level PLC for allocation of generation capacity costs and a negative Network Service Peak Load ("NSPL"), which are used in the allocation of transmission costs.[28] Allowing negative PLCs and negative NSPLs for net-metered customer-generators in FE's service territory is one of the key recommendations that I will discuss later in my testimony.

Q. If FE does not currently allow negative PLCs, how is the benefit of lower peak load from customer-generators accounted for? For example, if a net-metered customer-generator in Met-Ed territory produced excess generation during the 5CP hours during the summer of 2025, how would it impact Met-Ed customers starting June 1, 2026?

A. Regardless of whether FE explicitly measures and credits the customer-generator or the customer-generator's class for the reduced capacity benefit, the Met-Ed zone's peak load is reduced by all net-metered generation located on the distribution system as a function of basic physics. Whether an individual customer is assigned a negative PLC or a zero PLC

[28] Exhibit TM-4, ComEd PJM Open Access Transmission Tariff (Attachment M-2).

to account for that benefit does not impact the fact that the zonal coincident peak is lower due to the production from net-metered customers-generators. The PLC is simply an accounting construct at the customer and class levels to assign each customer and default service class its share of the zonal capacity obligation. As described above, each capacity zone (*e.g.*, Met-Ed, Penelec, ATSI for Penn Power, and APS for West Penn Power) is assigned a share of PJM system peak (zonal obligation) based on the capacity zone's 5CP usage.

Q. What is the connection between net-metered customer-generation coincident with the 5CP hours and a lower capacity obligation cost component of the various PTC Rider rates for FE customers?

A. The chain of actions which result in solar net-metered production coincident with the 5CP hours reducing the Commercial PTC Rider rate are as follows:

1. Net-metered excess generation coincident with the PJM 5CP hours reduces peak-hour load aggregate demand for the capacity zone of the net metering customer-generator (*e.g.*, during summer 2025).
2. That lowers the PLCs assigned to all retail customers in the capacity zone for the following delivery year (*e.g.*, June 2026-May 2027, which corresponds to the 2026-2027 delivery year).
3. That lowers future capacity procurement requirements (*e.g.*, for the 2026-2027 delivery year).
4. Which then in turn lowers default service supplier bid costs (*e.g.*, for the 2026-2027 delivery year).
5. Which then lowers the PTC Rider rate (*e.g.*, for the 2026-2027 delivery year).

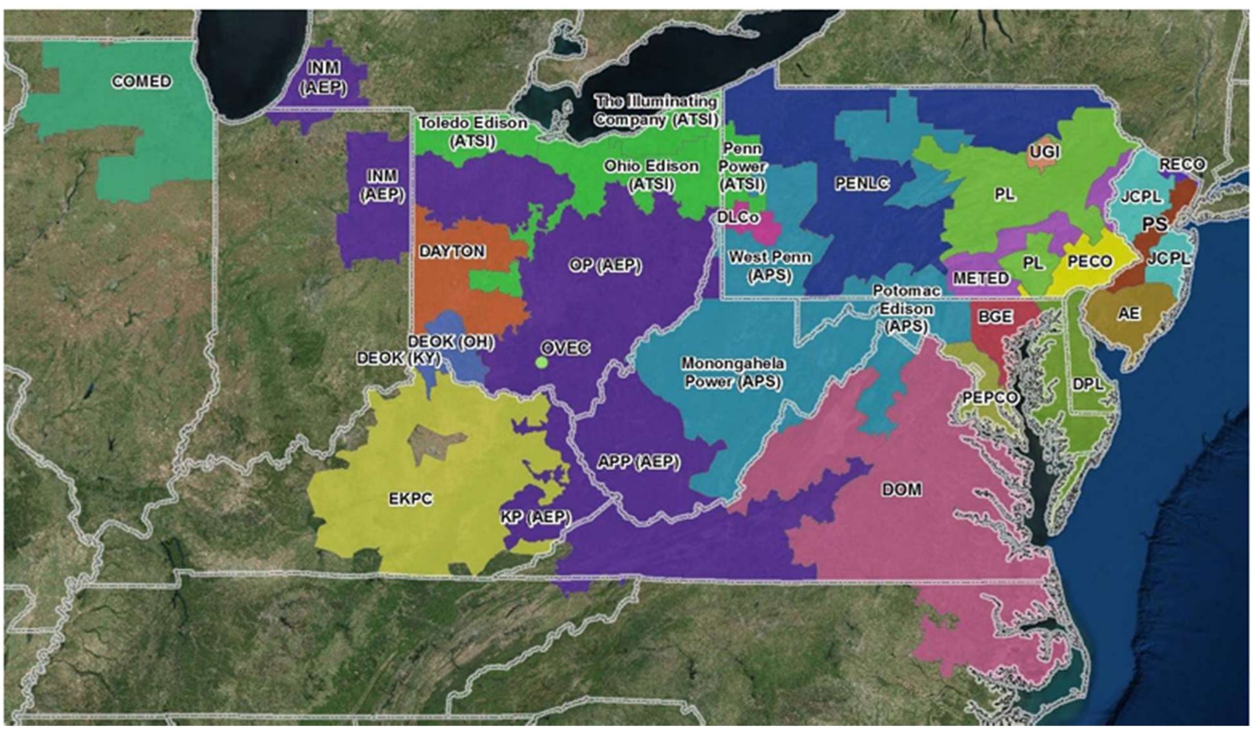
Q. Is it correct that, in the absence of FE allowing a customer to register a negative PLC, the peak load reduction benefit from net-metered excess generation during the 5CPs accrues to all retail customers in the PJM zone?

A. Yes. Unless FE explicitly credits the reduction in peak load to an individual customer or customer class, the benefit shows up in reduced zonal peak load, which reduces that zone's share of overall PJM capacity obligations.

Q. What are the PJM load zones associated with the FE Rate Districts?

A. Met-Ed and Penelec have their own stand-alone PJM load zones located entirely within the Commonwealth of Pennsylvania. Penn Power is part of the larger ATSI PJM load zone, which includes parts of Ohio. West Penn Power is part of the larger APS load zone, which includes parts of Maryland, Virginia, and West Virginia.

Figure 4: PJM Load Zones[29]



29 https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf

Q. What does this mean for electric distribution companies ("EDCs"), like Met-Ed and Penelec, that are also their own stand-alone PJM load zone?

A. It means that as currently constructed, the peak load reduction from net-metered customer-generator production during the 5CP hours accrues fully to ratepayers within the EDC.

Q. What does this mean for EDCs like West Penn Power and Penn Power that are part of a larger PJM zone that spans more than one state?

A. It means that as currently constructed, the peak load reduction benefit from net-metered customer-generator production during the 5CP hours accrues to all ratepayers within that broader PJM zone. In other words, the peak load reduction benefit from customer-generators in West Penn Power territory is currently being shared with customers in Maryland, Virginia, and West Virginia, and the peak load reduction benefit from customer-generators in Penn Power territory is currently being shared with customers in Ohio.

Q. Please provide more explanation on this point. Is it your testimony that in the absence of FE allowing the crediting of negative PLCs to a customer, the benefit of peak load reduction from Pennsylvania-based customer-generators is currently being shared with customers in Ohio, Maryland, Virginia, and West Virginia in the form of lower PJM capacity obligations?

A. For Penn Power and West Penn Power, that is correct. Most of those ATSI and APS capacity zone customers and loads are outside of Pennsylvania. That means the benefits created by Pennsylvania net-metered excess generation coincident with the 5CP hours in the form of lower capacity costs are shared primarily with non-Pennsylvania ratepayers. For Penelec and Met-Ed, since they have stand-alone PJM zones, the benefit is socialized across all their default service and shopping customers, all of whom are in Pennsylvania.

Q. Is it appropriate for customers in non-Pennsylvania load zones to benefit from reduced PJM capacity obligations stemming from Pennsylvania-based net-metered customer-generators?

A. No. It is inconsistent to have Pennsylvania ratepayers pay for the costs associated with compensating customer-generators while at the same time socializing the benefits associated with customer-generators across all ratepayers, including those in other states, particularly when there is an alternative in which all the benefits would accrue only to Pennsylvania ratepayers. From a cost allocation perspective, the ratepayers that bear the cost associated with compensating customer-generators should also be the ones to which FE allocates the benefits. It does not make sense to concentrate the costs of compensating net-metered customer-generators among a smaller group while socializing the monetary benefits across a larger group, especially when there is an appropriate solution that has already been implemented by another utility in PJM territory.

Q. Is the solution to have FE explicitly allocate the peak load reduction benefit at the EDC level (as is effectively being done currently in Penelec and Met-Ed due to their status as stand-alone PJM zones) instead of at the zonal level?

A. No. Even if FE could make such an allocation, which I am doubtful they currently could, that does not fully address the discrepancy between the customers to whom costs are allocated and the customers to whom benefits are allocated. Even in Penelec and Met-Ed, with stand-alone PJM load zones, the benefits associated with the peak load reduction from customer-generators are shared among all customers, including all default service customers and all customers that have opted out of default service and have chosen a third-party retail electric provider, also known as an electric generation supplier ("EGS") in Pennsylvania electric industry terminology.

Q. Which customers bear the costs associated with compensating customer-generators?

A. The costs associated with compensating customer-generators are borne by the customer class to which the customer-generator is classified. For customer-generators taking service under the Commercial PTC Rider, net-metering expenses are borne by ratepayers in the Commercial default service class. For customer-generators served under the HP Rider, the cost is borne by ratepayers in the Industrial default service class.

Q. Is there a straight-forward solution to stop socializing the benefits of reduced PJM capacity obligations from customer-generators to ratepayers outside of Pennsylvania, or to ratepayers that have third-party retail electric providers and do not bear the costs associated with compensating customer-generators?

A. Yes, there is an appropriate solution. If FE would allow PLCs to be negative for customer-generators, as implemented in ComEd's PJM Open Access Transmission Tariff (Attachment M-2), then the benefits of the negative PLCs, namely the lower PJM capacity obligation, would accrue to the applicable FE customer class that bears the costs of compensating net metering customer-generators. This would align with the general principle that the customers bearing the costs associated with customer-generators should be the ones to receive the benefits. As most FE net-metered customer-generators are or have applied to take service on the Commercial PTC Rider, then all those benefits would accrue to the Commercial default service class of the applicable FE Rate District by ultimately decreasing the PTC Rider rate. For net-metered customer-generators on the HP Rider, the benefits would accrue to the Industrial default service class.

Q. Would allowing for customer-level negative PLCs only benefit the default service customer-generators that can generate negative PLCs?

A. No. Default service customer-generators are already being compensated for capacity value under the PTC Rider and HP Rider tariffs. Allowing their customer-level PLCs to be negative will not impact their excess generation payout. This is purely a question of how the benefits of the peak load reduction are accounted for. As described earlier in my testimony, for customers taking default service, customer-level PLCs are added together to determine a PLC for the entire default service customer class, which helps determine that class's share of PJM capacity obligations for the following reliability year.[30] Negative default service customer-generator PLCs would be added together with the PLCs of other default service customers in the same class, leading to an overall reduction in that class's PJM peak load, and thus an overall reduction in that default service class's share of PJM capacity obligations.

Q. What is FE's reason for not allocating the benefit of the peak load reduction and reduced capacity obligation costs to the class that is bearing the costs of compensating customer-generators?

A. My understanding of FE's position on this issue comes from its response to a discovery question seeking information about how FE allocates the benefits of PJM 5CP load reduction from customer-generators.[31] When asked to explain how the benefit would be allocated, FE responded: "FE PA commercial customers currently on the PTC rate do not

[30] In practice each customer is assigned a PLC for each reliability year. That PLC follows the customer to whatever LSE they are served by (either a default service or a competitive electric generation supplier). Thus, the discussion here is simplified by assuming no switching from default service to an electric generation supplier or vice versa.

[31] Exhibit TM-5 (FE PA Response to JSA ROG Interrogatory Set 2, No. 9).

receive a benefit from excess generation from customer-generators."[32] When asked to elaborate on how other customer classes benefit from a reduction in PJM-related capacity charges, FE responded: "Not applicable."[33] This is in keeping with FE's position that customer-generators provide zero benefit in exchange for their compensation, which is not supported by the physics of how the grid operates, as I have explained in my testimony. Even if FE disagrees with the rate or process through which customer-generators are compensated, it is simply a reality of physics and accounting constructs that customer-generators provide real benefits to the grid in the form of avoided energy, capacity, and transmission costs.

Q. What is the implication for FE customers of FE's position that customer-generators provide zero benefits in exchange for their compensation?

A. FE's position—that zero benefits accrue to customers from customer-generators—means that the benefits of reduced PJM capacity obligations is defaulting to being shared across all customers within the customer-generator's PJM load zone, which includes non-Pennsylvania ratepayers as well as Pennsylvania ratepayers that have chosen to opt out of default service and shop for their electricity. In other words, FE's refusal to acknowledge the benefits of 5CP peak load reductions from customer-generators is leading to the concentration of costs for compensating customer-generators within the default service class of customer-generators but socializing the benefits across a much larger group of customers. In my opinion, this result is inconsistent with the objective of least-cost

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[32] *Id.*
[33] *Id.*

procurement for default service supply that is required by the Electricity Generation Customer Choice and Competition Act.[34]

Q. What is your recommendation to the Commission regarding the use of negative PLCs for customer-generators for the purpose of generation capacity?

A. I recommend that the Commission direct FE to allow negative PLCs in compliance with cost-based ratemaking and to achieve least-cost default supply procurement.

Q. Has the Commission approved the use of negative PLCs for customer-generators in other Pennsylvania electric utility service territories?

A. Yes. In approving the settlement agreement in UGI Utilities, Inc. – Electric Division's ("UGI") default service plan for the period June 1, 2025 through May 31, 2029 in Docket No. P-2024-3049343, the Commission approved new language in UGI's Rider B Generation Supply Service Surcharge that permits customer-generators to have a negative PLC.[35]

Q. Would it be necessary for FE to seek FERC approval to modify its PJM Open Access Transmission Tariff (Attachment M-2) to effectuate this recommendation?

A. I am not expressing a legal opinion, but I see nothing in FE's PJM Open Access Transmission Tariff ("Attachment M-2")[36] that precludes a customer from having a negative PLC. However, if tariff changes are required, as with all changes of tariffs, the authority having jurisdiction (in this case FERC) would have to approve those changes.

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[34] 66 Pa. C.S. Section 2801-2812.

[35] Docket No. P-2024-3049343, Joint Petition for Approval of Non-Unanimous Settlement, Appendix A (ProForma Tariff Supplement) at 41. ("Any expense/credit line items added by PJM related to these services shall be allocated by dividing the total charges by the total net GSR-2 PLC and NSPL values in order to determine the per unit of PLC rate and per unit of NSPL rates that will be assessed. Customer-generators may have PLC and NSPL negative values related to PLC and NSPL hours indicating net generation to which rates shall be assessed.")

[36] Exhibit TM-6, FirstEnergy Zone PJM Open Access Transmission Tariff (Attachment M-2).

C. Net-metered Excess Generation Reduces FE's Transmission Obligation

Q. Please explain what drives transmission costs in FE's service territory?

A. Transmission costs in FE's service territory are driven by PJM's Network Integration Transmission Service ("NITS"), which is the mechanism through which transmission owners recover the cost of building, operating, and maintaining the regional high-voltage transmission grid. Like PJM capacity costs, NITS costs are assigned based on each customer's contribution to peak transmission demand, measured by its NSPL.

Q. How is NSPL calculated, and how does it differ from the PLC used to allocate capacity costs?

A. NSPL and PLC share the same fundamental logic. Both measure a customer's contribution to peak demand and use that measurement to allocate system costs. But, for FE, they differ in three important ways: the peak hours used, the treatment of demand response events, and the timing of when new values take effect.

Q. Please elaborate on how the calculation of NSPLs differs from the calculation of PLCs with respect to peak hours used?

A. For capacity costs, as described earlier, a customer's PLC is based on its load during PJM's highest system-wide peak hours (the 5CPs) occurring between June 1 and September 30. Those PLC values take effect June 1 of the following year and remain in effect until May 31. For transmission costs, FE's Attachment M-2 specifies that a retail customer's NSPL is calculated using the five highest peak hours during whichever season -- summer (June 1 through September 30) or winter (December 1 through March 31) -- contains the applicable Transmission Zone peak as reported by PJM. The customer's average load during those five hours, grossed up for losses and scaled to match the Transmission Zone peak target, via a reconciliation factor, becomes that customer's NSPL.[37]

Q. Please elaborate on how the calculation of NSPLs differs from the calculation of PLCs with respect to the treatment of demand response?

A. For PLCs, load reductions from PJM demand response events are added back to produce an "unrestricted" peak load, ensuring that voluntary demand response curtailments do not affect a customer's capacity cost obligation. For NSPLs, FE's Attachment M-2 explicitly states that no such "add-back" applies.[38] This means that a customer that curtails load during a demand response event in an NSPL peak hour receives the full benefit of that curtailment in its NSPL calculation. As I will discuss, this makes the current exclusion of net-metered generation from the NSPL calculation more anomalous: the framework already recognizes and rewards load reductions from demand response in the NSPL calculation, but provides no parallel recognition for load reductions from customer generation.

Q. Please elaborate on how the calculation of NSPLs differs from the calculation of PLCs with respect to timing?

A. While PLC values take effect June 1 and remain in effect through May 31, NSPL values typically reset January 1 of the following calendar year. This means that a customer's transmission cost obligation can shift at a different point in the year than their capacity cost obligation.

Q. How does FE allocate NITS costs to its customers?

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[37] Exhibit TM-6, FirstEnergy Zone PJM Open Access Transmission Tariff (Attachment M-2) at 5-6.
[38] *Id*. at 6.

A. The allocation of NITS costs from the transmission zone level down to individual customers follows a structure parallel to the capacity cost allocation described earlier:

1. The Transmission Zone's NITS Rate is Established. Each FE transmission zone files an Annual Transmission Revenue Requirement ("ATRR") with FERC, reflecting the total annual cost of transmission infrastructure serving that zone. That revenue requirement, divided by the zone's single highest annual peak load, produces the zonal NITS rate expressed in $/MW-year.
2. Each Customer's NSPL is Calculated from Metered Data. On a customer-by-customer basis, FE calculates each retail customer's NSPL by identifying the five peak hours during the applicable seasonal peak period, measuring the customer's average metered load during those hours, grossing up for losses, and applying an NSPL Daily Scaling Factor to ensure the sum of all customer NSPLs matches the Transmission Zone target reported by PJM.
3. Individual Customer NSPLs Determine Each Customer's Share of Class Transmission Costs. Each retail customer's NSPL determines its proportional share of its customer class's total NITS cost obligation, flowing through to the applicable PTC Rider or HP Rider rates in the same manner as capacity costs.

Q. Do net-metered customer-generators that produce during the peak transmission hours used to calculate NSPL receive a negative NSPL?

A. No. Under FE's current practices, as with PLCs, the minimum NSPL assigned to any customer is zero. A net-metered customer-generator that is a net supplier to the grid during a NSPL peak hour is treated identically to a customer drawing no load at all, receiving no recognition for the transmission cost reduction its generation provides to other customers in the zone. This is particularly anomalous given that, as noted above, FE's own Attachment M-2 already recognizes demand response load reductions in the NSPL framework. Net-metered generation that reduces net load during a peak hour has the same physical effect on the transmission system as demand response curtailment, but the two are treated differently for NSPL purposes under FE's current practices.

Q. Has the Commission approved the use of negative NSPLs for customer-generators in other Pennsylvania electric utility service territories?

A. Yes. In approving the settlement agreement in UGI's default service plan for the period June 1, 2025 through May 31, 2029 in Docket No. P-2024-3049343, the Commission approved new language in UGI's Rider B Generation Supply Service Surcharge that permits customer-generators to have a negative NSPL.[39]

Q. Are negative NSPLs prohibited by FERC or PJM?

A. No. As with negative PLCs, FERC has explicitly approved the use of negative NSPLs for another PJM utility. ComEd in Illinois has implemented a tariff under which load attributable to net-metered and community solar projects may reflect both consumption and generation in the NSPL calculation, and therefore can result in a positive or negative value for any individual customer. Importantly, ComEd's FERC-approved tariff specifies that in no instance can an LSE's total transmission costs be allowed to go negative — meaning the negative NSPL benefit is bounded at the LSE level. Individual customer NSPLs may go negative, reducing that customer class's aggregate share of zone

[39] Docket No. P-2024-3049343, *Joint Petition for Approval of Non-Unanimous Settlement*, Appendix A (ProForma Tariff Supplement) at 41. ("Any expense/credit line items added by PJM related to these services shall be allocated by dividing the total charges by the total net GSR-2 PLC and NSPL values in order to determine the per unit of PLC rate and per unit of NSPL rates that will be assessed. Customer-generators may have PLC and NSPL negative values related to PLC and NSPL hours indicating net generation to which rates shall be assessed.")

transmission costs, but the zone itself cannot receive a net credit.[40] The same structure would apply to FE if it adopted negative NSPLs for net-metered customer-generators.

Q. What is the connection between net-metered customer-generator production coincident with the NSPL peak hours and a lower transmission cost component of the PTC Rider rate?

A. The chain of actions is directly analogous to the capacity cost chain described earlier:

1. Net-metered excess generation coincident with the NSPL peak hours reduces aggregate net load for the applicable FE transmission zone.
2. That lowers the NSPLs assigned to all retail customers in the zone for the following calendar year.
3. That lowers the zone's total NITS cost obligation for the following year.
4. Which lowers default service supplier bid costs for the following year, or in the case if FE's proposal was approved for DSP VII, FE's cost for acquisition costs would decrease.
5. Which lowers the PTC Rider or HP Rider rate for the following year.

Q. Does the same cross-state subsidy concern raised in the capacity cost section apply to transmission costs for Penn Power and West Penn Power customers?

A. Yes, and for the same structural reason. Because Penn Power's transmission load sits within the ATSI zone and West Penn Power's sits within the APS zone, both of which span multiple states, the NSPL-based transmission cost reduction benefit from Pennsylvania-based net-metered customer-generators is currently socialized across all customers in those broader multi-state zones. Pennsylvania default service ratepayers bear the cost of

[40] Exhibit TM-4, ComEd PJM Open Access Transmission Tariff (Attachment M-2) at 3.

compensating those customer-generators, while the transmission cost reduction benefit is shared with customers in Ohio, Maryland, Virginia, and West Virginia. For Met-Ed and Penelec, which are stand-alone transmission zones, the benefit is at least socialized entirely within Pennsylvania, but it is still spread across all customers in the zone, including shopping customers who do not bear the costs of compensating customer-generators. Allowing negative NSPLs at the customer class level -- precisely as ComEd has implemented -- would return that benefit to the Pennsylvania default service customer class that bears the associated costs, consistent with the principle that costs and benefits should be allocated to the same group of ratepayers.

Q. Historically, when have FE's transmission zone peaks typically occurred?

A. The following table shows the PJM Network Service Peak Loads for the four FE Pennsylvania transmission zones for the 2024, 2025, and 2026 NSPL years, reflecting zonal transmission peaks that occurred in calendar years 2023, 2024, and 2025, respectively.

Table 4: PJM Network Service Peak Loads for 2024[41], 2025[42], and 2026[43]

Transmission Zone	Year	Zonal Peak (MW)	Date	Hour (EPT)
APS	2026	9,791.6	1/22/2025	7-8 AM
	2025	8,937.6	1/22/2024	7-8 AM
	2024	9,302.9	12/23/22	5-6 PM
ATSI	2026	12,658.7	6/24/2025	3-4 PM
	2025	12,508.3	6/20/2024	2-3 PM

[41] PJM Network Service Peak Loads (NSPL) for 2024. Available at: https://www.pjm.com/-/media/DotCom/markets-ops/settlements/network-service-peak-loads-2024.pdf
[42] PJM Network Service Peak Loads (NSPL) for 2025. Available at: https://www.pjm.com/-/media/DotCom/markets-ops/settlements/network-service-peak-loads-2025.pdf
[43] PJM Network Service Peak Loads (NSPL) for 2026. Available at: https://www.pjm.com/-/media/DotCom/markets-ops/settlements/network-service-peak-loads-2026.pdf

	2024	11,963.0	9/5/2023	4-5 PM
Met-Ed	2026	2,999.9	6/24/2025	6-7 PM
	2025	3,066.9	7/16/2024	3-4 PM
	2024	2,890.1	9/6/2023	5-6 PM
Penelec	2026	2,908.6	1/22/2025	8-9 AM
	2025	2,953.2	7/10/2024	2-3 PM
	2024	2,762.8	9/6/2023	5-6 PM

The data reveal meaningful variation in when transmission zone peaks occur across the four FE zones. Met-Ed and ATSI (which includes Penn Power) have shown a consistent pattern of summer peaks, with Met-Ed peaking in September 2023, July 2024, and June 2025 across the three years shown, and ATSI peaking in September 2023, June 2024, and June 2025. By contrast, Penelec has shown a mix of winter and summer peaks, with peaks in September 2023, July 2024, and January 2025. APS (which includes West Penn Power) has produced consistent winter peaks – December 2022, January 2024, and January 2025. This variability stands in contrast to the PJM capacity 5CP hours, which by definition always occur during the summer months of June through September.

Q. What does the variability in FE's transmission zone peak timing mean for solar PV customer-generators' ability to reduce transmission costs?

A. For zones where transmission peaks have consistently occurred during summer afternoon hours, most notably ATSI (Penn Power) and Met-Ed, the alignment with solar PV generation, and thus the ability to reduce transmission cost obligations, is quite strong. As shown in Table 3, presented earlier in this testimony, a representative single-axis tracker facility in central Pennsylvania generates at 34–58% of rated capacity during the 2:00 PM to 6:00 PM EDT window that has captured most of the ATSI and Met-Ed transmission peaks in recent years. For zones where transmission peaks have occurred during winter morning hours, most notably APS (West Penn Power), which peaked between 7:00 AM and 8:00 AM in January in both 2024 and 2025, the alignment with solar PV generation is low. Solar generation is low during winter morning hours, meaning that solar PV net-metered customer-generators in West Penn Power territory would provide less reduction in the transmission zone peak that drives NSPL calculations for years in which transmission peaks occur in the winter.

Q. Does the lower correlation of transmission zone peaks with solar PV generation impact your recommendation to allow the generation of negative NSPLs?

A. No. The policy case for allowing negative NSPLs rests on a principle that applies regardless of generation type: customers whose generation reduces net load during transmission peak hours should have that contribution reflected in their NSPL. Solar PV is simply one technology among many. The negative NSPL and negative PLC frameworks are technology-neutral by design, crediting any generation that measurably reduces net load during the relevant peak hour, regardless of fuel source. A dairy digester, a combined heat and power facility, or a wind installation that happens to generate during a winter morning peak hour would provide the same measurable transmission benefit that the current framework fails to recognize. For solar PV customer-generators specifically, the zone-by-zone picture is mixed. As the transmission peak data above show, Met-Ed and ATSI (Penn Power) have consistently peaked during summer afternoon hours – precisely the window during which solar PV generation is strongest. Customer-generators in those zones are likely to generate meaningful negative NSPL values under the proposed reform. For APS (West Penn Power), which has peaked during winter mornings in recent years, solar PV generation would be low at the time of the zone peak, and the practical fiscal impact of the reform would be more modest for that zone. Penelec falls somewhere in between, having alternated between summer and winter peaks across the three years shown, meaning that solar PV customer-generators may or may not contribute depending on the year. Ultimately, this variability is an argument *for* the reform, not against it. Rather than requiring regulators to predict in advance which technologies and which zones will align with transmission peaks, a negative NSPL framework allows each customer-generator's actual metered output during the relevant peak hour to speak for itself. Zones and technologies that align will naturally generate negative NSPLs; those that do not align will not generate negative NSPLs. The framework is self-correcting by design.

Q. How would the allowance of generating negative NSPLs impact FE customers?

A. Similar to PLCs, the benefit of allowing NSPLs to be negative is to permit the benefits of negative NSPLs to accrue to the applicable default service customer class from which a net-metered customer-generator takes service. As most FE net-metered customer-generators are on or have applied to be on the Commercial PTC Rider, most of the benefits would accrue to the Commercial default service class of the applicable FE Rate District by ultimately decreasing the Commercial PTC Rider rate. For customer-generators under the HP Rider tariff, their negative NSPLs would ultimately reduce the HP Rider class's rate.

Q. What is FE's reasoning for not allocating the benefit of the peak load reduction and reduced transmission obligation costs to the class that is bearing the costs of compensating customer-generators?

A. My understanding of FE's position comes from its response to a discovery question about how FE allocates the benefits of transmission peak load reduction from customer-generators. When asked how the benefits of a decrease in transmission peak load are allocated among its ratepayers, FE replied: "Not applicable."[44] When asked to explain how a reduction in transmission peak load from net-metered customer-generator production could impact other customers, FE stated:

> Transmission costs are an allocation of costs by class of service and depend on the load contributions of responsible entities at the coincident peak. While excess generation at the coincident peak could theoretically affect load share, any actual reduction or reallocation is dependent upon the actions of other entities, including customers. Furthermore, peak load contribution is only one factor in the calculation of retail transmission costs. Thus, any excess generation from net metered customers does not necessarily result in any increase or decrease in transmission costs for retail customers and wholesale default suppliers.[45]

Q. What is your interpretation of FE's response to this question about the benefits of customer-generator peak load reductions and how they are allocated?

A. FE's response does not directly address how the benefits of transmission peak load reduction from customer-generators are allocated among its ratepayers. When asked that specific question, FE responded, "Not applicable," which is the same response it provided when asked the parallel question about capacity cost benefits. Given the detailed NSPL allocation framework that I have already explained, I do not find FE's characterization to be accurate. FE further states that because peak load contribution is "only one factor" in the calculation of retail transmission costs, excess generation from net-metered customer-generators "does not necessarily result in any increase or decrease in transmission costs." Notably, unlike FE's response to the parallel capacity cost question (to which FE stated that customer-generators provide no benefit to other customers), its transmission response stops short of that categorical denial, acknowledging instead that excess generation "could

[44] Exhibit TM-7, FE PA Response to JSA ROG Interrogatory Set 4, No. 1.
[45] *Id*.

theoretically affect load share." This implicit acknowledgment that a transmission benefit exists, even if qualified, is itself significant. Regardless, a lower aggregate NSPL for a PJM zone does directly reduce that zone's share of NITS costs, which in turn reduces the applicable PTC Rider or HP Rider rate. The fact that NSPL is one component among several does not mean changes in NSPL have no transmission cost impact.

Q. What is the implication for FE customers due to FE's failure to account for the transmission cost reduction benefits provided by net-metered customer-generators?

A. The practical consequence is the same as in the capacity cost context: the benefits of reduced transmission peak load from net-metered customer-generators are socialized across a broad group of ratepayers, including non-Pennsylvania ratepayers in the ATSI and APS zones, while the costs of compensating those customer-generators remain concentrated within the default service customer class.

Q. Do you believe that the Commission should direct FE to correct this problem?

A. Yes. FE's practice results in a problematic cost-benefit allocation asymmetry that the Commission should direct FE to correct.

Q. What is your recommendation to the Commission regarding the use of negative NSPLs for customer-generators for the purpose of transmission cost allocation?

A. The Commission should direct FE to allow negative NSPLs for net-metered customer-generators for the same reason it should direct FE to allow negative PLCs. Doing so would (1) align transmission cost allocation with the physical reality that net-metered excess generation reduces peak transmission demand, (2) correct the current anomaly by which demand response reductions are recognized in the NSPL framework but equivalent generation reductions are not, and (3) ensure that the transmission cost reduction benefits created by Pennsylvania net-metered customer-generators accrue to the Pennsylvania default service customer class that bears the costs of compensating those generators, rather than being socialized across a broader group of ratepayers that does not share those costs.

Q. Would it be necessary for FE to seek FERC approval to modify its Attachment M-2 to effectuate this recommendation?

A. As I stated regarding my negative PLC recommendation, I am not expressing a legal opinion, but I have found nothing in FE's Attachment M-2 that would preclude a customer from having a negative NSPL.

Q. You have provided thorough explanations of how net-metered customer-generators could decrease the rate impacts that were put forth in Exhibit DMY-7. Are you able to provide alternative estimates of the Commercial PTC Rider impacts with and without the allowance of negative PLCs and negative NSPLs?

A. Yes. Before turning to that quantification in Section V, I will address the full range of value that net-metered customer-generators provide to the grid — including benefits that flow to the compensating customer class specifically, and others that are more broadly shared.

IV. FE'S ESTIMATE OF IMPACT OF NET-METERING PROJECTS DOES NOT CONSIDER ADDITIONAL SOCIALIZED BENEFITS

A. Value of Solar Overview Discussion and Analysis

Q. Please describe the relevance of an assessment of the value of net-metered excess generation to the issues addressed in your testimony.

A. When considering an appropriate compensation rate for net-metered excess generation, the value associated with such generation provides a useful benchmark to evaluate the reasonableness of such compensation. Specifically, given that FE proposes to move certain net-metered customer-generators from the PTC Rider to the HP Rider, such a proposal begs the question: does the value associated with such generation justify compensation at a level more similar to the PTC Rider rate or the HP Rider rate?

Q. Please outline your general approach for developing an assessment of the value of net-metered excess generation.

A. For the analysis presented in this testimony, I assessed the value of net-metered excess generation from a FE ratepayer perspective. As such, only benefits that result in dollar savings for FE customers, either directly or indirectly, were quantified. Notably, this includes benefits that flow to customer classes outside the customer-generator's class. To estimate such benefits, I leveraged publicly available studies, PJM-reported data, and third-party data when necessary to assemble its best estimate of $/kWh benefits over the 2023/2024, 2024/2025, and 2025/2026 delivery years.

Q. What other perspectives are typically explored when conducting a value of solar analysis?

A. The value of solar analysis can be conducted from a range of perspectives. Most typically, in addition to a ratepayer perspective, analysis is conducted from the perspective of the control area (*i.e.*, PJM) as a whole, or from the perspective of society at large.

Q. What were the results of your value of solar analysis?

A. The results of my analysis are provided below in Table 5. Importantly, this analysis represents the FE ratepayer perspective, meaning that only benefits that flow to the ratepayers of the FE Rate District in question are included. As discussed throughout this testimony, under FE's proposed approach, certain benefits may be realized by customers outside of the customer-generator's class.

Table 5: Total FE Ratepayer Value of Solar in $/MWh by Delivery Year

Delivery Year	Penelec	Met-Ed	West Penn Power	Penn Power
2023/2024	$57.60	$58.75	$47.10	$70.10
2024/2025	$68.13	$73.29	$55.52	$78.89
2025/2026	$111.68	$117.96	$102.73	$121.24

Q. How would a value of solar analysis from a PJM or societal perspective change the results, and what is the implication for the purposes of your testimony?

A. Generally, the ratepayer perspective adopted in this analysis is the most restrictive in terms of the benefits quantified and applied. For instance, a PJM perspective may include benefits that accrue to customers of other utilities, including out-of-state ratepayers, resulting from the price suppressive effects of incremental solar generation on wholesale energy and capacity prices. In addition, a societal perspective would generally include benefits associated with environmental and human health impacts of avoided fossil generation. Thus, the results presented in this analysis are intended to represent a subset of total potential benefits that are both monetizable and accrue to FE customers.

Q. Are you including the value of alternative energy credits ("AECs") in your value of solar analysis?

A. No. While the production of AECs could provide value to FE ratepayers, I assume they do not, because the net-metered customer-generators are assigned the AECs and therefore monetize the AECs for their own benefit and not to the benefit of ratepayers.

Q. What components of the value of net-metered excess generation did you quantify in the analysis presented in this testimony?

A. I quantified benefits associated with energy, capacity, transmission, and demand reduction induced price effects ("DRIPE"). DRIPE benefits were applicable to both energy and capacity. For capacity and transmission benefits, I separately quantified benefits associated with solar generation's ability to reduce the share of fixed costs borne by FE customers (*i.e.*, FE's slice of the cost "pie") in addition to benefits associated with solar generation reducing total capacity and transmission expenses borne by all relevant PJM utilities (*i.e.*, the size of the cost "pie"). This results in the following benefit categories:

1. Energy
2. Capacity (Reduced Share of Costs + Reduced Total Costs)
3. DRIPE (Energy + Capacity)
4. Transmission (Reduced Share of Costs + Reduced Total Costs)

Q. Please provide an overview of each value component and its relevant attributes.

A. A high-level overview of each value component and to whom each component's value accrues is provided below in Table 6. In all cases in which potential benefits accrue to parties other than FE customers, I only included the portion of benefits attributed to FE customers in the results presented.

Table 6: Summary of Benefit Components – As Proposed by First Energy

Value Component	Units	Component Value Provided	To Whom Component Value is Provided	How Value is Included in DSP Rate	What portion of value flows through to DSP of FE C-G's customer class (vs. socialized over all of PJM)?
Energy	kWh	Avoided energy sales	DSP of C-G's customer class	Hourly LMP	Full value flows through
Capacity - Share of Costs (*i.e.*, reduction of FE's slice of pie)	kW	Decrease in PLC based on PJM 5CP Metric	All customers in the same FE District applicable capacity zone	Embedded in HP Cap-AEPS-Other Purchases	Still primarily socialized, though a larger fraction of the aggregate PLC reduction goes to DSP of C-G's customer class relative to benefits socialized PJM-wide
Tx - Share of Costs (*i.e.*, reduction of FE's slice of pie)	kW	Decrease in NSPL based on Tx Zone hybrid 1CP/5CP metric	All customers in the FE Utility District TX zone via Reconciliation Factor	Currently embedded in HP Cap-AEPS-Other Purchases, proposed as a separate component line item	Still primarily socialized, though an even larger fraction of the aggregate NSPL reduction goes to DSP of C-G's customer class relative to benefits socialized PJM-wide
Capacity - Total Cost Reduction (*i.e.*, reduction of size of pie)	kW	Decrease in capacity obligation for subsequent reliability years	All PJM customers	Embedded in HP Cap-AEPS-Other Purchases	Socialized
Tx - Total Cost Reduction (*i.e.*, reduction of size of pie)	kW	Decrease (theoretically) in relevant ATRR	All customers of PJM Tx zone	Currently embedded in HP Cap-AEPS-Other Purchases, proposed as a separate component line item	Socialized
DRIPE - Energy	kWh	Increased low-cost supply results in a decrease in energy price	All PJM customers	Hourly LMP	Socialized
DRIPE - Capacity	kW	Increased low-cost supply results in a decrease in capacity price	All PJM customers	Embedded in HP Cap-AEPS-Other purchases	Socialized

Q. For the energy benefit component, please describe in greater detail the component value provided and to whom the value is provided.

A. I have confirmed that FE does not monetize excess generation received from net-metered customer-generators; instead, FE treats this energy as a load reducer.[46] As such, the energy benefit component represents the value associated with avoided energy purchases due to the net negative contribution from customer-generators. As discussed above, such energy is assigned to the default service supplier of the customer-generator's class, and thus the value accrues to the same default service customers to which net-metering expenses accrue.

Q. For the capacity benefit components, please describe in greater detail the component value provided and to whom the value is provided.

A. I quantified two "pie" related benefits associated with capacity.

First, utilities are assigned capacity obligations based on their peak load contribution during PJM's 5CPs. As such, solar generation acting as a load reducer occurring coincident with PJM's 5CP would reduce the **share** of PJM-wide capacity expenses borne by the utility serving a customer-generator. This process is explained in detail earlier in my testimony. Notably, this benefit would not change the total costs region-wide but rather would shift costs away from the utility in question. Such benefits would accrue to all customers in the same capacity zone.

Second, while the capacity rights of net-metering customers are not monetized via bidding into the PJM forward **capacity** market, the capacity of projects still provides benefits to ratepayers in PJM more broadly because of how peak load reductions impact

[46] *See*, Exhibit TM-8 (FE Response to JSA ROG Interrogatory Set 2, No. 4) and FE PA Statement No. 1 at 17:12-14, which states "… excess energy from intermittent net-metered customer-generators is recognized financially as an aggregate reduction of the load served by winning bidders in the Company's default service auctions."

the development of inputs to PJM's forecasted capacity requirements. It ultimately lowers the quantity of MW of unforced capacity that PJM sets to be procured (*i.e.*, the quantity of capacity demanded or the capacity demanded "size of pie"). Specifically, solar generation during PJM's 5CP hours acts as a load reducer and would be reflected in data informing planning assumptions and thus reduce the total costs associated with capacity region wide. Such benefits would accrue to all customers within the PJM region, but I have only quantified the portion of benefits that would be realized by customers in the relevant FE Rate District due to reduced demand for capacity PJM-wide.

Q. For the transmission benefit components, please describe in greater detail the component value provided and to whom the value is provided.

A. Similar to the capacity benefits, I have quantified two "pie" related benefits associated with transmission.

First, solar generation acting as a load reducer occurring coincident with the seasonal zonal 5CP can reduce the NSPL applicable to the transmission zone. As a result, net-metered excess generation contributions to lowering the NSPL can result in reduced share of transmission charges (*e.g.*, NITS costs) for the customers in the applicable FE Rate District.

Second, solar generation acting as a load reducer occurring coincident with the seasonal zonal 5CP can defer transmission investments to the extent that peak load growth absent the load reduction effect of solar would have required additional system investments. The costs associated with such future buildout (*i.e.*, future "size of the pie" increases) is reflected in Transmission Enhancement Charges, which recover costs associated with system expansion. Such benefits (or, avoided Transmission Enhancement

Charges) would flow to all customers of a transmission zone, given that the cost of any buildout would also be allocated across such customers.

Q. For the DRIPE benefit components, please describe in greater detail the component value provided and to whom the value is provided.

A. The energy and capacity DRIPE benefit components quantify the price impact of the reduction in wholesale demand caused by generation within the distribution network. Specifically, solar acting as a load reducer can reduce demand for energy and capacity in wholesale markets, thereby resulting in a lower clearing price as compared to a scenario in which such solar generation did not reduce demand. In other words, in both cases, the reduction in demand drives the marginal unit to be lower in the supply curve, resulting in cheaper clearing prices. This benefit component is unique in that it describes a monetized benefit, but one that is not directly measurable given that it is the product of an indirect market impact.

The benefit of this price suppression is realized through the resulting reduced energy and capacity prices. Given this, the benefits are socialized to all PJM customers. However, for the purposes of our analysis, I quantify only the benefits that accrue to the FE Rate District in question.

Q. Are there other components that were not quantified that represent potential value to FE customers under a ratepayer perspective?

A. Yes. I identified two additional benefits that are likely non-zero but are difficult to quantify. As such, I have not quantified such benefits but include discussions of them below for the purpose of building the record. These are: (1) avoided distribution investments, and (2) benefits from interconnection upgrades funded by customer-generators.

Q. Please describe the avoided distribution investment and explain why it was not quantified.

A. Similar to avoided transmission investments, solar interconnected to the distribution system has the potential to reduce peak load experienced by distribution infrastructure. Such peak load reductions will defer certain capacity-related distribution investments, producing an avoided cost benefit. However, the quantification of such benefits can be difficult, given that the impact of solar on the distribution system is location- and context-specific. Given this, it is difficult to derive a utility- or state-wide average for modeling, especially given a lack of identified third-party studies on this topic. As such, I determined that, although this benefit is likely non-zero, it is most appropriate to note it at a conceptual level but not quantify in dollar terms.

Q. Please describe the benefits from interconnection upgrades funded by customer-generators and why they were not quantified.

A. Customer-generators interconnecting to the distribution system are often required to fund system modifications necessary to facilitate their interconnection. These upgrades are often sized to allow for sufficient hosting capacity headroom for the project in question. It is possible that the upgrades funded by customer-generators also will deliver shared benefits to FE ratepayers more broadly. For example, a net-metered project may have to fund an upgrade of the local distribution circuit to enable its output to be moved to the nearest distribution substation. This upgrade may increase the capacity of that circuit to serve other new loads from that upgraded circuit and provide a new source of local generation to serve load growth from that distribution substation. In addition, upgrades funded by customer-generators could result in the early replacement of infrastructure relied on by ratepayers, thereby creating value by deferring ratepayer-funded replacements of such infrastructure. Finally, infrastructure that is upgraded at the customer-generator's expense may provide the opportunity to use enhanced control and remote sensing equipment which provides reliability benefits.

These benefits were not quantified because, similar to avoided distribution investments, they are context- and location-specific. In addition, the interconnection of distributed generation could also pose reliability costs that would need to be accounted for. Given this, I determined that, although this benefit is likely positive, it is most appropriate to note it at a conceptual level but not quantify it in dollar terms.

B. Value of Solar Methods

Q. How did you quantify the benefit categories discussed above?

A. First, I started with the conceptual understanding discussed above of FE's accounting practices, PJM cost allocation practices, and net-metered customer-generators' impact on metrics relevant to such practices. Next, I assembled relevant market and solar PV performance data, including publicly available studies, PJM-reported data, and supplemental third-party data when necessary. Such data was leveraged to produce high-level estimates of the value of solar in \$/kWh terms for the 2023/2024, 2024/2025, and 2025/2026 delivery years. A detailed description of my methods for each benefit component is provided below.

Q. What did you use for PV performance data?

A. I utilized production outputs from the SAM published by the National Laboratory of the Rockies. A single location of State College, Pennsylvania was used because it approximates the geographic center of Pennsylvania and is thus expected to represent a rough average of irradiance experienced by solar projects for all FE Rate Districts. SAM produces production estimates specific to a historical weather year, in addition to a typical meteorological year ("TMY"). Both types of output were used for varying benefit components, as described below. I adopted SAM model defaults for a majority of solar PV system configuration inputs, but revised SAM inputs to model a single-axis tracking facility, as opposed to the fixed-axis default. Hourly production outputs were transformed to adjust for daylight saving time as SAM's default results are presented in standard time.

Q. For benefit components that relate to peak load reductions, how did you quantify such reductions?

A. Peak load reductions are a function of the assumed hourly PV production profile and hourly load. For all benefits relating to peak load reductions (namely, capacity and transmission-related benefits), I utilized actual historical hourly load as provided by the PJM Data Miner, combined with PV production data based on actual historical weather years from 2021-2024 to determine the solar capacity factor (*e.g.*, coincidence factor) at relevant peak hours. PV production based on historical weather years were used to ensure that the same weather informing load curves was reflected in PV production curves.

Depending on the benefit component in question, the 1CP, representing the single annual peak, or the 5CP, representing the average coincidence over the top five peak hours, was utilized. For 5CP calculations, I only applied one peak per day (*e.g.*, excluding consecutive peaks from a single weather event), consistent with the practices reflected in PJM's reporting of historical peaks.[47] In addition, certain benefit components required an assessment of peak load from the RTO perspective or the zonal perspective. Such specifics

[47] For example, *see*: https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/summer-2024-peaks-and-5cps.pdf.

are discussed below. In all cases, the weather-year-specific coincidence factors calculated from 2021-2024 were averaged to produce a single representative value for the benefit and/or zone in question.

Q. How did you calculate the avoided energy benefit component?

A. To calculate the avoided energy benefit component, I calculated the weighted average Locational Marginal Prices ("LMPs") applicable to each FE Rate District's zone over each delivery year. LMPs were weighted based on the TMY production curve from SAM, reflecting the impact of solar PV's daily and seasonal variation on avoided energy value. The resulting prices were then grossed up to reflect distribution-level line losses specific to each utility, reflecting that if such energy had not been avoided at the distribution level, additional kWh would need to be generated from transmission-connected generators to meet the same customer load. Transmission line-losses were not included in the gross up, given that the price impacts of transmission line losses are already included in LMPs. For the 2025/2026 delivery year, which has not closed at the time of the analysis, I utilized a forecast of hourly LMPs provided by Standard and Poors to fill out the delivery year. Given this, for the 2025/2026 delivery year, the values reported represent a blend of actual and forecasted prices.

Q. How did you calculate the capacity benefit associated with reduced share of capacity costs?

A. First, I collected historical capacity prices for each delivery year assessed. Zone-specific capacity prices were used in any years in which constraints produced differential pricing to the RTO.[48] Next, I calculated the PJM 5CP, as discussed above, resulting in a factor of

[48] In certain years, FE's various zones were constrained and thus resulted in capacity clearing prices higher than the overall RTO clearing price.

49%. This was then used to calculate a solar-specific $/MW-year benefit, reflecting solar's partial contribution to reducing the PJM 5CP. This value was then grossed up to account for utility-specific transmission and distribution line losses and then converted to a $/MWh value based on the assumed DC capacity factor of 17.5%. The assumed capacity factor was the average capacity factor resulting from SAM outputs for the weather years assessed (2021-2024).

Q. How did you calculate the capacity benefit associated with avoided capacity costs via reduced capacity requirements?

A. The process to calculate the capacity benefit associated with avoided capacity costs via reduced capacity requirements (*e.g.*, reducing the size of the cost "pie" that is allocated to all PJM utilities) is a similar process to the calculation of the benefit associated with the reduced share of capacity costs (*e.g.*, reducing the size of the slice of the cost "pie" assessed to a given utility). This is because capacity planning is expected to continue to rely on metrics such as the PJM 5CP when determining the capacity requirements in the region, and historical capacity prices are a strong proxy for the dollar value benefits of reductions to such requirements. Crucially, the primary difference in calculating this benefit is that it accrues to all utilities in PJM. As such, I de-rated this component to reflect only the share of benefits that would accrue to the FE Rate District in question. To do so, I utilized each utility's share of the total PJM Zonal 5CP as a proxy for how such allocations would occur. In addition, this benefit was grossed up to account for the planning reserve margin.

Q. How did you calculate the transmission benefit associated with the reduced share of transmission costs?

A. First, I compiled NITS rates, as reported by FE, from 2021-2026. Next, I calculated the seasonal zonal 5CP (that is, the zonal 5CP occurring during the season in which the 1CP is occurring). This coincidence factor was then used to de-rate the $/MW-yr NITS rates to reflect the share of solar PV production in relevant hours that contributes to reduced transmission cost allocations for the relevant FE transmission zone. This value was then grossed up to account for utility-specific transmission and distribution line losses,[49] converted to delivery year, and then converted to a $/MWh value based on the assumed DC capacity factor of 17.5% referenced above.

Q. How did you calculate the transmission benefit associated with avoided transmission costs via reduced transmission requirements?

A. First, we compiled Transmission Enhancement Charges specific to each zone from 2021 through 2025, as reported by PJM.[50] These values (in $/MWh) were then translated to PV-specific $/MWh values using an identical process to the one described above, applicable to the reduced share of transmission costs benefit component. Finally, the resulting value was de-rated to reflect only the share of benefits flowing to the FE Rate District in question, given that benefits accrue to all customers in the relevant transmission zone.

Q. For both Energy and Capacity DRIPE benefit components, please describe the primary source on which you based its modeled results.

[49] Transmission losses are included in LMP prices for energy, so there is no separate transmission loss adjustment for energy. However, a loss adjustment is appropriate for the avoided capacity components.
[50] Available at: https://www.pjm.com/markets-and-operations/billing-settlements-and-credit.

A. I used the report entitled *Pennsylvania Demand Reduction Induced Price Effects Study* ("DRIPE Study") submitted to the Pennsylvania Public Utility Commission in May 2024 by the PA Act 129 Statewide Evaluator and prepared by Demand Side Analytics.[51]

Q. Based on the DRIPE study referenced above, explain how you calculated the Energy DRIPE benefit components.

A. I utilized the published Energy DRIPE Year 1 values for Planning Year 18 (delivery year 2026/2027) for each FE Rate District. I converted the published Energy DRIPE Year 1 values for 2026/2027 to historical years by indexing such values to historical zonal energy prices, as compared to forecasted zonal energy prices provided by Standard and Poors.

Q. What additional adjustments were made to the Energy DRIPE values reported in the DRIPE study?

A. Given that the values reported in the study represented the DRIPE values accruing to all of Pennsylvania, I de-rated such values based on each FE Rate District's share of total Pennsylvania load.[52] This adjustment was intended to approximate the energy DRIPE benefits that would apply to the specific FE Rate District in question, consistent with the ratepayer perspective of this value of solar analysis.

Q. Please describe what information you utilized from the primary source to determine the Capacity DRIPE benefit components.

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[51] Exhibit TM-9. PA Act 129 (PA HB 2200, passed in 2008) amended several existing sections of the PA Public Utility Code with the overall goal of reducing energy consumption and demand by imposing new requirements on EDCs. As part of the implementation of Act 129, the Commission contracted with a Statewide Evaluator to monitor and verify data collection, quality assurance, and the results of each EDC's Energy Efficiency and Conservation Plan. The goal of the study was to present a methodology for quantifying two key Act 129 avoided cost components (1) Energy DRIPE for the EDC service territories and (2) Capacity DRIPE for the load zones of each of the Pennsylvania EDCs.

[52] Utility load was calculated using 2023 EIA Form 861 Data. Accessible at: https://www.eia.gov/electricity/data/eia861/.

A. I utilized the data and description of methodology on page 5 of the DRIPE study to calculate the associated Capacity DRIPE for each delivery year. Specifically, the report provides the specific formula, supporting market data, and PJM auction results necessary to calculate the associated Capacity DRIPE for a given delivery year.

Q. Please describe how you calculated the Capacity DRIPE benefit components.

A. The DRIPE Study suggests Capacity DRIPE for a given delivery year is equal to the cleared MW for that delivery year and zone multiplied by the supply curve slope. For the 2025/2026 calculation of capacity DRIPE, a supply curve slope value was not provided in the DRIPE Study so I inferred a supply curve slope value by transforming the 2024/2025 slope value by the ratio of the respective market clearing prices.

V. CORRECTION OF THE QUANTIFICATION OF NET METERING IMPACTS ON PTC RATES

Q. Does FE's cost impact analysis, as provided in Exhibit DMY-7, account for the various benefits customer-generators provide, as discussed in this testimony?

A. No. Exhibit DMY-7 analysis assumes that customer-generators represent a pure cost to ratepayers that provide zero benefits in exchange for the compensation provided. On the capacity and transmission side, this is at least analytically consistent with FE's position that these projects do not provide a clear capacity or transmission benefit to ratepayers; but FE ignores the fact that reduced PLC and NSPL values from customer-generator production are already flowing to ratepayers within the applicable PJM load zone in the form of lower capacity and transmission cost obligations. On the energy side, the fact that FE's analysis ignores the benefits customer-generators provide in the form of avoided energy costs is not analytically consistent. As discussed in Section III, FE's own accounting practices already recognize the avoided energy benefit from customer-generators by crediting it back to the customer-generator's default service customer class through the reconciliation charge, resulting in lower Commercial PTC Rider rates for default service customers. It is difficult to reconcile FE's omission of this same benefit from their cost impact analysis with their own implicit treatment of the energy benefit in their billing practices.

Q. At a high level, how should we view FE's presentation of a cost impact analysis that assigns zero benefits to customer-generators?

A. FE is entitled to disagree with the method or rate at which customer-generators are compensated—that is a legitimate policy debate. But disagreement with the compensation rate does not justify omitting the benefits side of the ledger entirely. A cost impact analysis that accounts for costs while systematically excluding benefits will overstate the net cost of customer-generators to ratepayers. The Commission should not rely on FE's incomplete analysis as the basis for decisions affecting default service customers.

Q. Based on the energy, capacity, and transmission benefits that you have discussed above, please present your re-calculation of the impacts of net metered customer-generation on FE's Commercial PTC Rider rates.

A. I have attached to this testimony as Exhibit TM-10 my re-calculation of Exhibit DMY-7.

Q. Which of the benefits discussed in Section III did you include in Exhibit TM-10?

A. I have included the full energy benefits, capacity share-of-costs benefits, and transmission share-of-costs benefits.

Q. Please explain why you focused specifically on these three benefits?

A. I included the full energy benefits, capacity share-of-costs benefits, and transmission share-of-costs benefits because they represent benefits that are directly monetizable given known accounting practices and provide value in the near term. Given these reasons, these three categories of benefits were in line with my assessment of Exhibit DMY-7 as a short-term snapshot of impacts on Commercial PTC Rider rates and net metering expenses. Further, including energy was an obvious choice as FE is already including the benefit, it just wasn't accounted for in Exhibit DMY-7. The capacity share-of-costs benefits, and transmission share-of-costs benefits are easy to conceptualize, and align with Exhibit DMY-7 as FE is focusing on Commercial PTC Rider customers taking on 100% of the share of net metering expenses without realizing any fraction of the share of benefits that should accrue to Commercial PTC Rider customers.

Q. Why did you exclude the other value of solar benefit stack components in your corrections to Exhibit DMY-7?

A. The reasons vary depending on the component. For capacity total-cost-reduction and particularly transmission total-cost-reduction the benefits materialize in the longer term when the relative decrease in the need for additional infrastructure and resources is realized. That is, it is unknown when and how deferred transmission investments would be realized. Regardless, such benefits probably do not have an immediate impact on investment decisions, while Exhibit DMY-7 was focused on the immediate feedback loop that would impact Commercial PTC Rider rates in the short-term. I did not include energy DRIPE and capacity DRIPE benefits because of the complexity of accounting for the change in DRIPE values over time as derived from the DRIPE Study. That is, the DRIPE Study estimates the impact of demand reduction on price to change over the first four years after physical operation of the project or measure, and then assumes the DRIPE benefits to dissipate to zero. Accounting for this would introduce complexity given the need to track each cohort of projects and estimate different levels of DRIPE impact by cohort vintage. Further, as the DRIPE benefits are transitory, I did not want to mislead the reader or distract the analysis with benefits from net metering projects where the benefits will ramp down after 2029; the Exhibit DMY-7 analysis timeframe.

Q. Does the exclusion of DRIPE and total-cost-reduction benefits make your estimate of the total benefits offsetting net metering expenses in Exhibit TM-10 conservative?

A. Yes.

Q. How does the methodology used to develop Exhibit TM-10 compare to Exhibit DMY-7?

A. Exhibit TM-10 presents an identical structure to Exhibit DMY-7, with the exception that I have included the aforementioned benefits from net=metered customer-generators as an offset to net metering expenses in the calculation of the net metering true-up expenses. Given this, Exhibit TM-# reflects a more accurate account of the resulting Commercial PTC Rider rates over the four-year horizon displayed because it includes benefits that will be implicitly monetized in Commercial PTC Rider rates as a result of such projects.

Q. How did you account for the impacts of negative PLC and negative NSPL in Exhibit TM-10?

A. Given that Exhibit DMY-7 relates to net metering impacts on customer class expenses, the issue of whether a customer can register a negative PLC and negative NSPL has significant impacts on the resulting net cost and true-up expense calculated. Given this, I present two sets of results that capture the offsetting benefits of net-metered projects to the Commercial default service class based on whether a customer-generator is permitted to register a negative PLC and negative NSPL or not.

Q. How do the results of Exhibit TM-10 compare to those shown in Exhibit DMY-7?

A. When the benefits of expected net-metered excess generation are fully considered, the upward rate pressure of additional net metering customer-generators on Commercial PTC Rider rates is far less than what FE claims in Exhibit DMY-7. As shown below in Table 7, when using the Exhibit DMY-7 construct to make an apples-to-apples comparison, I calculate that the impact over the 2026-2029 period will be between 11% and 55% of FE's estimated impact shown in Exhibit DMY-7, depending on if negative PLCs and negative NSPLs are allowed.

Table 7: Calculated Net Metering Expense Across all FE Rate Districts (Exhibit DMY-7 Mid-Case Installation Assumptions, $/kWh)

Source	Includes Offsetting Benefits?	Includes Negative PLC/NSPL?	2026	2027	2028	2029
FE DMY-7	No	No	$0.123	$0.128	$0.149	$0.200
Exhibit TM-10	Yes	No	$0.068	$0.071	$0.082	$0.110
Exhibit TM-10	Yes	Yes	$0.014	$0.015	$0.018	$0.024

Q. What should we conclude from the fact that your results show significantly lower cost impacts from net metering expenses when the projects benefits are netted against its costs, particularly when your proposed negative PLC and NSPL reforms are incorporated?

A. First, it is not surprising that an analysis that accounts only for the costs associated with a product and none of the benefits shows a shockingly high-cost impact number. This analysis assumes that customer-generators are being compensated in exchange for providing exactly zero value to the grid, when, as discussed extensively in this testimony, this is simply not true. Secondly, accounting for the benefits side of the ledger -- even conservatively, as I have done here -- meaningfully reduces the cost impact associated with customer-generators on the Commercial PTC Rider. And most importantly, this analysis shows that when my proposed PLC and NSPL reforms are accounted for, the cost impact to default service customers is almost neutral. While I have not completed an analysis and forecast of the MW growth of net metering customer-generators in the FE Rate Districts, assuming the Exhibit DMY-7 mid-case growth rate assumption are correct, my analysis also highlights that not allowing for negative PLCs and NSPLs will cost FE default service customers $7.7 million in 2026, rising to $108.9 million in 2029. These are real monetary benefits that, absent action from the Commission directing FE to change its practices, will be shared among customers in Ohio, Maryland, Virginia, and West Virginia. These monetary benefits should instead be allocated to the default service customers that are paying for the customer-generators' services by implementing my negative PLC/NSPL framework.

VI. ESTABLISHING LEGACY RIGHTS UNDER THE COMMERCIAL PTC RIDER

Q. Please explain the concept of legacy rights.

A. As used in my testimony, the concept of legacy rights refers to the provision of certain protections or exemptions in a utility electric tariff or other authority that allows a customer to continue receiving utility service under the pre-existing terms of a tariff following a material change to the rate schedule. In this context, material changes could include the addition or modification of rules applicable to a certain rate schedule or the closure of a rate schedule or rate option. Legacy rights are synonymous with the concept of "grandfathering" of projects or facilities. In general, legacy rights are based upon principles of fairness and regulatory gradualism, as well as the recognition of investment-backed expectations made by customers given the information then available.

Q. Please explain why it is important to establish appropriate legacy rights in this proceeding.

A. Legacy rights provisions will determine how operational and in-development net-metered projects are classified and treated under the Commercial PTC Rider and Industrial HP Rider if the Commission approves the MRPL proposal described in FE Witness Young's direct testimony. As applied to this proceeding, legacy rights would allow certain qualifying net-metered projects to remain on the Commercial PTC Rider as they would in the absence of the MRPL proposal, rather than be shifted to the Industrial HP Rider rate. FE recognizes the importance of legacy rights as FE in fact proposed an (inadequate) legacy rights framework as part of its showing. Specifically, Witness Young proposed that net-metered projects that are operational and generating electricity by June 1, 2027 would not be subject to reclassification from the Commercial PTC Rider to the Industrial HP Rider based on MRPL for a two-year period ending June 1, 2029.[53]

Q. Please comment on FE Witness Young's proposed legacy rights framework.

A. FE's proposed legacy status framework does not provide reasonable protections to net-metered projects that are either operational or have made significant progress towards achieving operational status. Further, FE's proposed short, two-year transition period does not accomplish regulatory gradualism.

In light of the deficiencies of FE's proposed legacy rights, I am proposing an alternate legacy rights framework that recognizes the significant investments incurred by

[53] FE PA Statement No. 1 at 19:18-22.

project owners at different stages of project development while also considering the true-up expenses recovered from the Commercial PTC Rider customers. My legacy rights proposal would ultimately accomplish FE's plan to transition net-metered customer-generators to the Industrial default service class, but it would provide a more reasonable transition period than proposed by FE. As I will describe later in my testimony, my recommendation establishes legacy rights for two tiers of net-metered projects: (1) operational or near-operational projects, and (2) mature pre-construction projects.

A. Justification and Objectives for Legacy Rights

Q. Please explain why it is appropriate for a legacy rights framework to be established in this proceeding.

A. The projects that would be impacted by FE's revised MRPL framework, which primarily consist of solar PV generators, require significant upfront capital investment incurred by project owners and involve extended development timelines. Throughout the development of a project, an owner incurs significant pre-installation costs associated with site control, interconnection studies, and the construction of grid system upgrades needed to accommodate safe interconnection of the project. These types of pre-construction costs can be in the hundreds of thousands of dollars.

At each step of the development process, project owners must consider the potential financial benefits of their investment decisions against the upfront costs of developing that project. At each decision point, the project owner must rely on the information available and known to them at that time, which includes the rules and terms by which a customer rate schedule is determined and the associated compensation provided to a net-metered project under a specific rate schedule. Altering the rules and terms of a customer rate schedule, and therefore the compensation for net-metered excess generation, without appropriate and gradual rate transition protections risks undermining prior investment decisions that help achieve the goals of the AEPS Act with respect to alternative energy development and would likely discourage future project development in the Commonwealth.

Q. Are there any other considerations with respect to legacy rights beyond the financial impacts to net-metered project owners?

A. Yes. A key issue in this proceeding is the potential upward pressure on the Commercial PTC Rider rate over time due to an increase in the number of net-metered projects within the Commercial default service class. In prior sections of my testimony, I demonstrate how the cost savings benefits of net-metered excess generation can and should be realized to mitigate that impact, particularly when the negative PLC and negative NSPL cost allocation metrics that I have recommended are adopted and implemented. I recognize that the Commercial default service class is limited in its ability to absorb additional net-metered excess generation due to the size of its load requirements, and I also recognize that a legacy rights framework must be fair to all customer groups and insulate them against rate shocks. My proposal will ensure fair treatment to the Commercial default service class and balance the interests of both net-metered project owners and Commercial default service customers.

Q. How does your legacy rights framework balance the interests of project owners and Commercial default service customers?

A. The framework outlined below distinguishes two tiers of legacy rights based on project maturity levels, which has a direct correlation with the amount of investment a project developer has incurred for a project, and applies a reduced compensation level for Transitional Projects to mitigate any upward pressure on the Commercial PTC Rider rate.

Q. What are the primary objectives of your legacy rights framework?

A. As previously stated, the JSA's legacy rights framework is intended to appropriately balance the interests of both project owners and Commercial default service customers, as reflected in the following objectives:

1. Provide a reasonable level of protection for both Commercial default service customers and owners of net-metered projects that achieves a reasonable and equitable outcome for both groups.
2. Minimize future risk and uncertainties related to default service procurement.
3. Ensure that the qualification thresholds applicable to Operational and Transitional Projects (as defined below) are transparent and practicable to mitigate any future disputes and administrative requirements incurred by FE.

B. Joint Solar Advocates' Legacy Rights Proposal

Q. Please summarize the JSA's proposed legacy rights framework.

A. The JSA's legacy rights framework bifurcates projects into two tiers based upon their status as operational or in-development. For each tier, the framework provides for (1) qualification or eligibility criteria and (2) a defined legacy rights duration that is applicable to all net-metered projects in FirstEnergy's service territory, regardless of the specific FE Rate District in which that project is located.

The first tier of the legacy rights framework applies to projects that are either currently operational or provide a completed copy of their Certificate of Completion[54] to FE on or before June 1, 2027 ("Operational Projects"). Operational Projects would maintain their classification on the Commercial PTC Rider and be compensated at the full value of the PTC Rider rate for their excess generation for a 25-year period.

The second tier of the framework applies to pre-construction, non-yet operational projects that demonstrate the achievement of certain project development maturity thresholds by June 1, 2027 ("Transitional Projects"). Transitional Projects would also maintain their classification on the Commercial PTC Rider but would receive a reduced level of compensation equal to 90% of the PTC Rider rate for their excess generation for a 15-year period. In order to qualify as a Transitional Project, the project owner must demonstrate achievement each of the following milestones:

1. Submitted an interconnection application to FE on or before the date in which the instant default service plan was filed (*i.e.*, February 3, 2026).
2. Executed an interconnection agreement with FE by June 1, 2027 (*i.e.*, the date by which FE's Default Service Plan VII is proposed to begin).
3. Received net metering approval (if applicable) from the Commission as required by 52 Pa. Code §75.13(a)(5).
4. Signed a Construction Services Agreement (if applicable) by June 1, 2027, which is a document provided by FE that generally outlines the responsibilities for designing,

[54] A Certificate of Completion, as defined in 52 Pa. Code § 75.22, is a certificate in a form approved by the Commission containing information about the interconnection equipment to be used, its installation and local inspections.

constructing, and paying for any electric system upgrades required to interconnect the project.

5. Paid an initial deposit equal to 10% of the interconnection payment per the terms of the Construction Services Agreement (if applicable) or requested from FE for an invoice to pay the initial 10% interconnection payment, by June 1, 2027. In the event that a project owner requests an interconnection deposit invoice from FE, FE should be required to provide such an invoice within 60 days of the project owner's request.

All other net-metered projects that do not meet the eligibility requirements for treatment as an Operational or Transitional Project would be subject to any revised MRPL metric approved by the Commission in this proceeding and, depending on their specific circumstances, placed on the Industrial HP Rider.

Q. Please elaborate on the rationale underlying the JSA's legacy rights framework for Operational Projects?

A. The legacy rights treatment for Operational Projects aligns with FE's proposal that those projects which become operational on or before the start of the Default Service Plan VII (*i.e.*, June 1, 2027) should be allowed to maintain their current classification as a Commercial default service customer. However, the 25-year legacy status period included in the JSA's framework is more aligned with the operational lifetime of a solar generation asset than the two-year legacy status period proposed by FE. Further, FE's rationale for providing an overly restrictive two-year legacy period (because two years is the "mid-point of the DSP VII term"[55]) is inconsistent with any operational or financing realities of solar PV net-metered projects.

[55] Exhibit TM-11 (FE PA Revised Response to JSA ROG Interrogatory Set 2, No. 12).

That is, this proposed treatment for Operational Projects also recognizes that these projects have made complete or nearly complete investments, upwards of millions of dollars, including payments to FE for system upgrades that are necessary to safely interconnect the projects to the electric grid. Due to the extended timeline associated with these types of assets, project owners incurred these investments well before the MRPL proposal was made in this proceeding, meaning that an owner could not have reasonably known that the terms and compensation associated with the Commercial default service rate was at risk of being upended. These types of projects deserve legacy status protection under the basic rate principle of fairness, as commonly recognized in other state jurisdictions.

Q. Please elaborate on the rationale underlying the JSA's legacy rights framework for Transitional Projects?

A. The milestones and associated timing for determining the eligibility of Transitional Projects are intended to ensure that the most mature net-metering projects, which have made significant investments albeit lower than those by Operational Projects, are afforded legacy treatment as Commercial default service customers for a reduced number of years. By ensuring that legacy status is provided to those projects that meet the milestones before the start of the Default Service Plan VII (*i.e.*, June 1, 2027), the framework attempts to appropriately mitigate the amount of net metering expenses assigned to the Commercial default service class. Additionally, by reducing the compensation to these projects by 10% below the Commercial PTC Rider rate, the framework reduces the net metering expenses for Commercial default service customers. If combined with my recommendation for FE to allow for negative PLCs and negative NSPLs, the Transitional Projects are likely to provide greater benefits (as quantified in lower Commercial PTC Rider rates) to default service customers from just the combination of avoided wholesale energy LMP benefits, reduced share of capacity costs assigned to the default service customer class, and reduced share of transmission costs assigned to the default service customer class than would have occurred in the absence of any Transitional Projects.

VII. CONCLUSION

Q. Please summarize your recommendations.

A. I recommend that the Commission adopt my proposed approach for addressing issues associated with excess generation from customer-generators assigned to the Commercial default service class, which consists of the following proposals:

1. The Commission should require FE to modify how it calculates customer peak loads used to determine generation capacity and transmission cost allocation by: (1) allowing customers to register "negative loads" as a result of the excess generation they produce, and (2) apply the cost savings of those negative loads to reduce the allocation of the relevant costs to the default service class in which the customer-generator is assigned.
2. The Commission should adopt my proposal for establishing legacy rights under the Commercial PTC Rider for all net-metered customer-generators that are operational or provide a completed copy of their Certificate of Completion to FE on or before June 1, 2027.
3. The Commission should adopt my proposal for establishing legacy rights under the Commercial PTC Rider, at a reduced rate, for all net-metered customer-generators that meet certain project development maturity milestones on or before June 1, 2027.

Q. Does this conclude your testimony?

A. Yes. However, I reserve the right to submit such additional testimony as may be necessary or appropriate.

APPENDIX A
DEFINED TERMS USED IN TESTIMONY

Capacity Zone
A PJM-defined area used to allocate capacity obligations (*e.g.*, Met-Ed, Penelec, ATSI, APS).

Default Service
Electric generation supply provided by the Electric Distribution Company to customers who do not choose a competitive supplier.

Electric Generation Supplier
A competitive Electric Generation Supplier that provides generation services (*e.g.*, energy, capacity, transmission, ancillary services) to a FE customer, in lieu of the customer taking default service via the HP or PTC Riders.

HP Rider
Industrial Hourly Pricing Rider customers which large (currently => 100 kW in peak demand) default service customers are assigned. The HP Rider rate is a fixed rate for each three month period plus the variable 15-minute load weighted load weighted price based on the applicable FE zonal locational marginal price (LMP).

Maximum Registered Peak Load
A customer's net demand contribution impact to FE's default service procurement activity, as determined upon the net power flow from or into FE's distribution or transmission system. As related to customer-generators, the Maximum Registered Peak Load is inclusive of the nameplate capacity of the generation system.

Net-Metering Customer-Generator
A retail customer operating an eligible net-metered generation facility under Pennsylvania law. In my testimony, unless otherwise stated specifically, I am referring to a FE retail customer with no native load, apart from the station load required to operate the net-metered generation facility.

Network Service Peak Load (NSPL)
A retail customer's contribution to transmission zone peak demand used to allocate Network Integration Transmission Service costs.

Price-to-Compare (PTC)
The EDC's default service rate, reflecting the blended cost of procured supply.

Commercial PTC Rider
Price to Compare Rider for which customers (currently with a peak demand of < 100 kW) are eligible to receive, unless the customer elects to receive default service under the Industrial Hourly Pricing Rider. The Commercial PTC Rider rate is a fixed $/kWh rate for a six-month period.

Peak Load Contribution (PLC)

A retail customer's contribution to system peak demand, based on the PJM five coincident peak (5CP) hours.

Transmission (NITS) Component
The zone used to allocate transmission costs (*e.g.*, MAIT, ATSI, Allegheny/APS).

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of FirstEnergy Pennsylvania Electric Company for Approval of its Default Service Program for the Period June 1, 2027 to May 31, 2031	: : : :	Docket No. P-2026-3060298

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a true copy of the foregoing Joint Solar Advocates' Direct Testimony upon the parties listed below in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a party).

Via Electronic Mail

Kenneth M. Kulak, Esq. Brooke E. McGlinn, Esq. Maggie E. Curran, Esq. Morgan, Lewis & Bockius LLP 2222 Market Street Philadelphia, PA 19103 ken.kulak@morganlewis.com brooke.mcglinn@morganlewis.com Maggie.curran@morganlewis.com *Counsel for FirstEnergy Pennsylvania Electric Company*	Tori L. Giesler, Esq. Angelina Umstead, Esq. FirstEnergy Service Company 341 White Pond Drive Akron, OH 44320 tgiesler@firstenergycorp.com aumstead@firstenergycorp.com

Elizabeth R. Marx, Esq.* Lauren N. Berman, Esq.* Ria M. Pereira, Esq.* John W. Sweet, Esq.* Levi A. Phillips, Esq.* Pennsylvania Utility Law Project 118 Locust Street Harrisburg, PA 17101 pulp@pautilitylawproject.org emarx@pautilitylawproject.org lberman@pautilitylawproject.org rpereira@pautilitylawproject.org; jsweet@pautilitylawproject.org; *Counsel for Counsel for the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania - CAUSE-PA*	Rebecca Lyttle, Esq.* Assistant Small Business Advocate Office of Small Business Advocate Forum Place 555 Walnut Street, 1st Floor Harrisburg, PA 17101 relyttle@pa.gov *Counsel for the Office of Small Business Advocate*
Steven C. Gray, Esq. Senior Attorney Assistant Small Business Advocate Office of Small Business Advocate Forum Place 555 Walnut Street, 1st Floor Harrisburg, PA 17101 sgray@pa.gov *Counsel for The Office of Small Business Advocate*	Harrison W. Breitman, Esq.* Katherine M. Kennedy, Esq.* Olivia M. Spergel, Esq.* Office of Consumer Advocate 555 Walnut Street Harrisburg, PA 17101-1923 HBreitman@paoca.org OSpergel@paoca.org KKennedy@paoca.org *Counsel for the Office of Consumer Advocate*
Melissa A Chapaska, Esq. * HMS Legal LLP 501 Corporate Circle Suite 302 Harrisburg, PA 17110 machapaska@hmslegal.com *Counsel for Penn Renewables LLC*	Todd S. Stewart, Esq. * HMS Legal LLP 501 Corporate Circle, Suite 302 Harrisburg, PA 17110 tsstewart@hmslegal.com *Counsel for Shipley Choice, LLC d/b/a Shipley Energy and Interstate Gas Supply, LLC d/b/a IGS Energy EGS Parties*

Susan E. Bruce, Esq. * Charis Mincavage, Esq*. Matthew Garber, Esq. * Rebecca Kimmel, Esq. * McNees Wallace & Nurick LLC 100 Pine Street P.O. Box 1166 Harrisburg, PA 17108 sbruce@mcneeslaw.com cmincavage@mcneeslaw.com mgarber@mcneeslaw.com rkimmel@mcneeslaw.com *Counsel for Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance, and West Penn Power Industrial Intervenors*	Aron J. Beatty, Esq. Duquesne Light Company 800 North Third Street Harrisburg, PA 17402 abeatty@duqlight.com *Counsel for Duquesne Light Company*
Michael Gruin, Esq. Donald Wagner, Esq. Stevens & Lee, P.C. 17 N. 2nd St., 16th Fl. Harrisburg, PA 17101 Michael.gruin@stevenslee.com Donald.wagner@stevenslee.com *Counsel for WGL Energy Services, Inc.*	Nicholas A. Stobbe, Esq.* Stevens & Lee, P.C. 17 N. 2nd St., 16th Fl. Harrisburg, PA 17101 Tel. nicholas.stobbe@stevenslee.com *Counsel for Customer-Generator Coalition*
Michael Gruin* Donald Wagner Stevens & Lee, P.C. 17 N. 2nd St., 16th Fl. Harrisburg, PA 17101 Michael.gruin@stevenslee.com Donald.wagner@stevenslee.com *Counsel for Town Square Energy East, LLC*	Whitney E. Snyder, Esq. Erich W. Struble, Esq. HMS Legal LLP 501 Corporate Circle, Suite 302 Harrisburg, PA 17110 wesnyder@hmslegal.com ewstruble@hmslegal.com *Counsel for The Pennsylvania State University*

Mark A. Hoyer Deputy Chief Administrative Law Judge mhoyer@pa.gov Erin L. Gannon Administrative Law Juge egannon@pa.gov	Colleen Kartychak, Esq. Marsha D. Makel, Esq.* Constellation Energy Generation, LLC 1310 Point Street Baltimore, MD 21231 colleen.kartychak@constellation.com linda.kizuka@constellation.com; Marsha.Makel@constellation.com *Counsel for Constellation Energy Generation, LLC and Constellation NewEnergy, Inc.*
Allison C. Kaster, Esq. Director & Chief Prosecutor Pennsylvania Public Utility Commission Bureau of Investigation and Enforcement Commonwealth Keystone Building 400 North Street Harrisburg, PA 17120 akaster@pa.gov *Counsel for PAPUC*	John M. White, Esq. Constellation Energy Generation, LLC 101 Constitution Avenue, N.W. Suite 400 East Washington, DC 20001 john.white@constellation.com *Counsel for Constellation Energy Generation, LLC and Constellation NewEnergy, Inc.*
Deanne M. O'Dell, Esq. Eckert Seamans Cherin & Mellott, LLC 213 Market Street, 8th Floor P.O. Box 1248 Harrisburg, PA 17101 dodell@eckertseamans.com *Counsel for the Retail Energy Supply Association*	Michael Gianantonio, Esq. Robert F. Daley, Esq. Robert Peirce & Associates, P.C. 707 Grant Street Gulf Tower, Suite 125 Pittsburgh, PA 15219 mgianantonio@peircelaw.com *Counsel for John Bevec and Sunrise Energy, LLC*
Daniel B. Markind, Esq. Flaster Greenberg, PC 1717 Arch Street, Suite 3300 Philadelphia, PA 19103 Daniel.markind@flastergreenberg.com *Counsel for Dimension PA 1 LLC*	Mitchell H. Kizner, Esq. Flaster Greenberg, PC Commerce Center 1810 Chapel Avenue West Cherry Hill, NJ 08002 mitchell.kizner@flastergreenberg.com *Counsel for Dimension PA 1 LLC*

Christopher O'Hara, Esq. PJM Interconnection LLC 2750 Monroe Boulevard Audubon, PA 19403 christopher.ohara@pjm.com *Counsel for PJM*	Lauren M. Burge, Esq.* Eckert Seamans Cherin & Mellott, LLC 600 Grant Street, 44th Floor Harrisburg, PA 17101 lburge@eckertseamans.com *Counsel for the Retail Energy Supply Association*
Jamie L. Martines, Esq.* Spilman Thomas & Battle, PLLC 301 Grant Street, Suite 3440 Pittsburgh, PA 15219 jmartines@spilmanlaw.com *Counsel for Walmart, Inc.*	Linda S. Kizuka, Esq.* Constellation 250 Massachusetts Avenue, NW Suite 760 Washington, DC 20001 linda.kizuka@constellation.com *Counsel for Constellation Energy Generation, LLC and Constellation NewEnergy, Inc.*
Barry A. Naum, Esq. * Steven W. Lee, Esq. Sarah D. Stoner, Esq.* Spilman Thomas & Battle, PLLC 1100 Bent Creek Boulevard, Suite 101 Mechanicsburg, PA 17050 bnaum@spilmanlaw.com slee@spilmanlaw.com sstoner@spilmanlaw.com *Counsel for Walmart, Inc*	

WITNESSES / CONSULTANTS

Mark Ewen* Industrial Economics, Incorporated 2067 Massachusetts Avenue Cambridge, MA 02140 MEwen@indecon.com *OSBA Witness*	Maksim Malukoff* Industrial Economics, Incorporated 2067 Massachusetts Avenue Cambridge, MA 02140 MMalukoff@indecon.com *OSBA Witness*
Serhan Ogur* Exeter Associates, Inc. 10480 Little Patuxent Parkway Suite 300 Columbia, Maryland 21044 OCAFEPADSP26@paoca.org *OCA Witness*	Barbara R. Alexander* Barbara Alexander Consulting, LLC 83 Wedgewood Drive Winthrop, Maine 04364 OCAFEPADSP26@paoca.org *OCA Witness*

Patrick M. Cicero* 118 Locust Street Harrisburg, PA 17101 pcicero@pautilitylawproject.org *CAUSE-PA Witness*	James L. Crist, P.E. Lumen Group, Inc. 4226 Yarmouth Drive, Suite 101 Allison Park, PA 15101 JLCrist@aol.com *PSU Witness*
Frank Lacey Electric Advisors Consulting 3 Traylor Drive West Chester, PA 19382 frank@eacpower.com *Retail Energy Supply Association Witness*	Thomas S. Michelman* Jim D. Kennerly* 161 Worcester Road, Suite 503 Framingham, MA 01791 tmichelman@seadvantage.com jkennerly@seadvantage.com *Solar Energy Industries Association and the Coalition for Community Solar Access Witness*
Stephen W. Chriss* 814 Respect Drive Bentonville, AR 72716 Stephen.Chriss@walmart.com *Walmart Witness*	Leah K. Armitage* Jim Heidell* Andy Reger* Lauren Rothermich* PA Consulting Group, Inc. 2420 17th St. Unit 220 Denver, CO 80202 leah.kunkel@paconsulting.com jim.heidell@paconsulting.com andy.reger@paconsulting.com lauren.rothermich@paconsulting.com *Customer Generator Coalition Witness*

Randall Miller* 2200 E. Williams Field Road, Suite 200 Gilbert, AZ 85295 miller@townsquareenergy.com *Town Square Energy Witness*	

FOX ROTHSCHILD LLP

Ashley L. Beach

Ashley L. Beach
PA Attorney I.D. No. 306942
747 Constitution Drive, Suite 100
Exton, PA 19341
Telephone: 610-458-2997
E-Mail: abeach@foxrothschild.com

Counsel for Solar Energy Industries Association and Coalition for Community Solar Access

Dated: April 29, 2026

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of FirstEnergy Pennsylvania Electric Company for Approval of its Default Service Program for the Period June 1, 2027 to May 31, 2031	:	Docket No. P-2026-3060298

VERIFICATION

I, Thomas S. Michelman, hereby declare that I am the Vice President & Senior Director, Distributed Energy Resources Practice Lead for Sustainable Energy Advantage, LLC, and that the facts set forth in the foregoing Direct Testimony are true and accurate to the best of my knowledge, information, and belief, and that I make this verification subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

By: Thomas S. Michelman

Dated: April 28, 2026

Thomas S. Michelman
Vice President & Senior Director, Distributed Energy Resources Practice Lead for Sustainable Energy Advantage, LLC